Exhibit C

Proposed Investment In

BCE-STACK Development LLC

For the Joint Development of

Oklahoma Energy Acquisitions, LP's assets in the STACK play

Bayou City Energy Management, LLC

Investment Committee Memorandum

Deal Team:

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I. Executive Summary

Investment Committee Recommendation

Bayou City Energy Management, LLC ("Bayou City" or "BCE") recommends funding BCE-STACK Development LLC ("DrillCo") for the purposes of prosecuting a drilling partnership with Oklahoma Energy Acquisitions, LP, a wholly owned subsidiary of Alta Mesa Holdings, LP ("AMH" or the "Company"), a top tier Mid-Continent operator, for the continued development of a rapidly emerging world class unconventional resource play. This investment will provide Bayou City Energy, L.P. (the "Fund") and its co-investors the opportunity to efficiently deploy drilling capital. Given the strong merits of the investment, as detailed in the following pages, the Deal Team recommends that the Investment Committee approve the transaction so that it may proceed to closing and calls for the funding of the first three wells in the drilling Development Plan for ~$9.6 million.

Introduction

BCE has committed to partner with AMH to form DrillCo, with the objective of drilling proven development wells in the Company's Kingfisher County, Oklahoma acreage in the STACK (Sooner Trend (oil field), Anadarko (Basin), Canadian and Kingfisher (counties)) play of central Oklahoma ("Subject Acreage") primarily targeting the Mississippian formation ("Mississippian", "Meramec", "Mississippi Lime", "Osage Lime", used interchangeably throughout document). Bayou City's initial capital commitment will be sufficient to fund its portion, subject to the terms of the Joint Development Agreement ("JDA"), of the development costs associated with 40 wells on the Subject Acreage, and in total will be no greater than $128 million. A Term Sheet related to a draft form JDA was executed by AMH and BCE on December 18, 2015. The term sheet provides BCE an initial period of exclusivity through January 15, 2016 in which to successfully complete its due diligence and negotiate the final form JDA. DrillCo was formed December 29, 2015, and will be initially capitalized in early January 2016 with the drilling of the first wells subject to the JDA to commence by February 2016.

Given the tremendous investment returns afforded by the Subject Acreage, BCE chose to diligently pursue this opportunity with full knowledge and expectation that the total capital requirement for DrillCo's obligations would exceed the maximum single investment cap out of the Fund ($37.5 million). Accordingly, BCE assessed several alternatives for funding the portion of DrillCo's obligations in excess of the Fund cap, including: (i) partnering with another private equity sponsor, or a specialist non-operated working interest fund, and receiving advantaged economics for providing the opportunity (a "promote"); (ii) utilizing term and or revolving debt; and (iii) offering the unfunded equity portion for co-investment to Fund limited partners ("LPs") with a below market promote to the Fund. The high-level of industry and financial interest in the STACK was an important competitive consideration for the both BCE and AMH, and effectively ruled out partnering with another, most likely larger, financial sponsor. Ultimately, in consideration of all of the pertinent factors, BCE decided that prudent utilization of low interest rate, revolving bank debt and offering the remaining equity in DrillCo as co-invest for Fund LPs was the best option for the fund and its various constituents.

Illustrative Co-Investment Term Sheet	
Opportunity:	**Partnering in the development of a world-class resource play with a leading operator**
Deal Highlights:	• Joint development of 40+ horizontal wells in the core of the STACK play of Kingfisher County, Oklahoma • Prolific wells supporting robust investment returns (50%+ IRR) even at today's low crude oil and natural gas prices • Investor ("DrillCo") capital exposure is limited upfront, Operating Partner is burdened with any overruns
DrillCo – Operating Partner Waterfall:	• DrillCo funds 100% of CapEx up to the $3.2 million per well cap • DrillCo receives 80% of cashflow until 15% IRR • DrillCo receives 20% of cashflow after 15% IRR until 25% IRR • DrillCo retains 7.5% interest thereafter
DrillCo Term (Exclusive):	Lesser of 4 years or the completion of the 40 joint wells. Further wells may be added by mutual election of DrillCo and Operating Partner
Gross Co-Investment CapEx:	$64 million (50% of 40 wells at $3.2 million per well)
Estimated Net CapEx:	~$45 to $50 million (with cashflow recycling)
BCE LP – Co-investor Waterfall:	• BCE LP and Co-investor split DrillCo CapEx 50-50 • BCE LP and Co-investor split DrillCo proceeds 50-50 until 15% IRR to Co-investor • Thereafter: BCE LP receives 75% of DrillCo proceeds and Co-investor 25%

With regards to the process undertaken for offering the co-investment opportunity to LPs, please see the memo attached as an Addendum.

Background

Will McMullen and Mark Stoner (the "BCE Partners") have a long professional history with the Company's Management: Will, during his time at Denham Capital (a private equity firm focused on oil and gas investments), helped oversee Denham's investment in Alta Mesa for several years. Additionally, during his time at White Deer, Will led an attempted recapitalization of the Company – a process which lasted for over 18 months. Before joining BCE, Mark held the position of VP of Finance at Alta Mesa and was a member of the Company's 12-person leadership team. Mark worked directly alongside the CEO (Hal Chappelle) and CFO (Mike McCabe) for over 7 years. Will and Mark's intimate knowledge of Alta Mesa's Management, assets and financial motivations was leveraged to structure this opportunity.

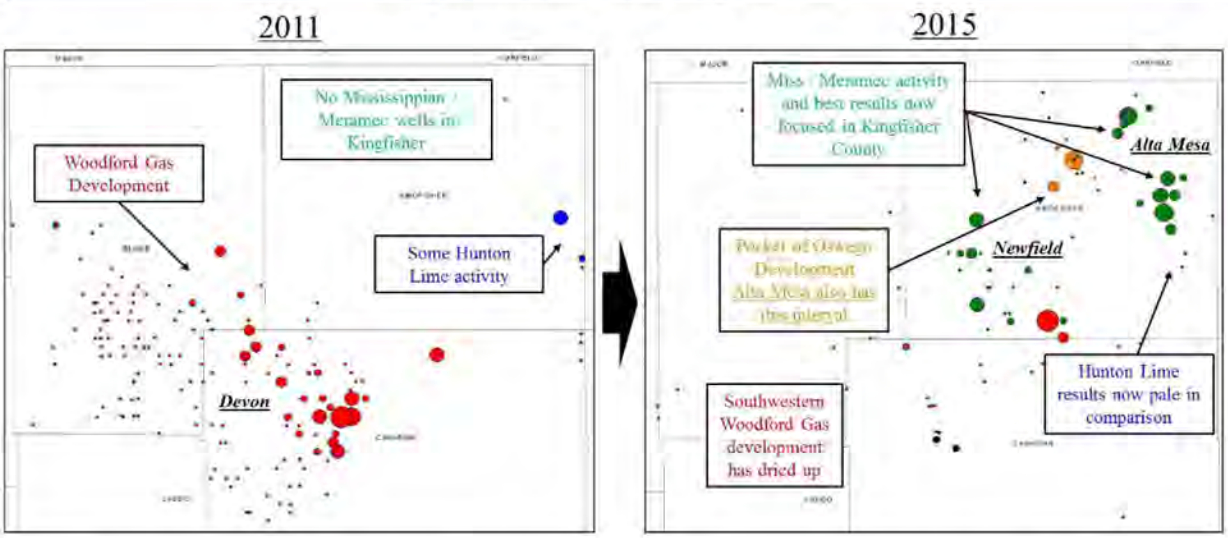
Concurrent with the formation of BCE, the BCE Partners developed an interest in the Company's STACK assets as a viable candidate for one of Bayou City's investment structures, the Drilling Partnership. BCE was attracted to the asset due to its relatively low development costs, prolific liquids-rich production, and presence within a de-risked, and well-established oil & gas operating region. BCE understood several of the internal AMH financial and growth dynamics which would make the DrillCo an attractive financing structure. Namely, in early 2015, AMH's CAPEX plans and balance sheet were under serious scrutiny by the public debt markets after a failed $210 million divestiture of Eagle Ford Shale assets on January 30, 2015. The Eagle Ford divestiture was anticipated to de-leverage the company, which had $320 million drawn on a $375 million credit facility at year-end 2014, and provide them adequate borrowing base capacity to continue their 3 rig STACK development program. The failed divestiture created a significant funding gap which necessitated curtailment of activity and outside financing. Importantly, AMH was forced to exit Q1'2015 with only a 1 rig program in the STACK.

This knowledge of the STACK asset and the financial condition of AMH led Bayou City to initiate a dialogue with Management in February 2015. BCE's proposals were largely rebuffed as AMH pursued second lien financing which they were able to close on June 2, 2015 in the amount of $125 million. Coincident with the second lien closing, AMH began a small private process to attract DrillCo partners. BCE was selected to participate in this process and took part in a technical meeting with Management on June 2, 2015. Armed with data from this meeting and prior discussions, BCE submitted an LOI to AMH Management on June 4, 2015 (see Addendum 1). Numerous meetings and discussions with Management later, BCE resubmitted an LOI on July 10, 2015 with several options and carried working interests dependent on the size of the commitment well count (see Addendum 2).

The proliferation and publication of DrillCo transactions throughout the first 7 months of 2015 provided AMH several comparative structures which they used as transactional barometers and negotiation fodder. Whereas BCE approached the DrillCo structure from a traditional energy private equity perspective, underwriting the transaction to a 25%+ IRR, the competitive landscape and capital providers which played in it were much more willing to underwrite the transactions to 12 – 18% IRRs, oftentimes with a capped upside. BCE's unwillingness to incorporate a ceilinged return into its resubmitted LOI made the re-submitted LOI uncompetitive and thus AMH elected to pursue other offers.

Despite having its offer declined by AMH, the northeast Kingfisher County STACK play remained a focus of BCE throughout the summer. BCE felt it had a competitive advantage sourcing opportunities in this part of the play due to its unique knowledge of the companies operating here, the predominance of which are private operators. The limited drilling results released voluntarily by the operators in this area of the STACK coupled with a one-year time lag on the disclosure of data reported to the Oklahoma Corporation Commission ("OCC") have until recently helped keep the quality of this asset hidden from the broader industry. Additionally, northeast Kingfisher County was historically developed by majors who formed large contiguous units for ease of water flooding. Thus the acreage tended to be held-by-production ("HBP") in significant blocks of acreage, leaving larger operators unable to accumulate enough acreage to make this part of the trend impactful to their asset base. The lack of insight into regional well performance, the inability to enter northeast Kingfisher county with the requisite scale to be meaningful to the larger independents (>100,000 net acres), and legacy Cana Woodford / SCOOP positions held by Devon, Newfield, and Cimarex in Blaine, Canadian and southwest Kingfisher Counties have until recently kept the area dominated by AMH off the radar.

Progression of the STACK Play 2011 - 2015



BCE management had asymmetric insight into real time data from this region of the STACK and throughout the summer proactively initiated DrillCo discussions with numerous STACK operators including Chaparral Energy, Longfellow Energy, Osage Exploration, Payrock Energy and Felix Energy. Executive level discussion occurred with both Chaparral and Longfellow, with BCE separately providing each an LOI; however, a commercial agreement was unable to be achieved with either company.

Meanwhile, Alta Mesa spent the balance of August through October negotiating and documenting at least one competing DrillCo financing which was expected to close prior to year-end 2015. However, the deal failed to close due to issues arising during the negotiation of the JDA. The inability to close on this transaction and the limited window in which AMH could source, structure and document an alternative DrillCo by year-end put in jeopardy broader parallel financial initiatives being undertaken by AMH and Highbridge (AMH's private equity sponsor).

The failure of AMH to close the competing DrillCo coincided with a series of email conversations, dinners and industry events at which BCE Management was able to re-socialize the BCE alternative with members of Alta Mesa

Management and Highbridge. Despite a series of prior DrillCo bids by BCE which were economically inferior, AMH elected to re-engage discussions with BCE because of BCE's unique insights into the asset and breadth of knowledge derived from the several months of diligence dating back to February 2015, BCE's commitment to reach an agreement by year-end 2015, and importantly, an existing high degree of personal and professional trust between the parties. This trust gave AMH the confidence BCE could move efficiently and in good faith to close.

BCE Capitalized on its Relationships to Secure the Deal
The timing of the failure of the competing DrillCo ultimately allowed BCE to reemerge in the process at a quite advantageous time for several reasons: • AMH was being directed by Highbridge to close / agree to terms on a transaction by year-end so that Highbridge could confidently commence a broader AMH corporate financing in which a definitive DrillCo was paramount. • In conjunction with its fall borrowing base redetermination, AMH completed an engineering review of its assets. The resulting reserve run showed a marked increase in reserves across AMH's STACK acreage, with an average PUD EUR of 585 MBOE (70% liquids). BCE was able to incorporate this updated data into its financial modeling and diligence process; whereas, competing DrillCo bids utilized an older set of data from AMH's June DrillCo process, with a 322 MBOE (79% liquids) reserve report type curve and a 398 MBOE (59% liquids) "Trending Type Curve" which reflected the current sample of Generation 2 wells.

BCE quickly moved to assimilate updated reserves, drilling performance and production data into a new structure. Importantly, BCE's re-engagement coincided with the completion of the reserve run used by AMH's senior banking group during their fall credit facility redetermination. On November 12, 2015, AMH announced that its borrowing base was increased from $255.0 million to $300.0 million (in a study conducted by Wells Fargo[1], Alta Mesa was one of seven operators to see an increase in its credit facility out of a universe of 44 peers). The basis of this significant increase in reserve value was the performance of the STACK assets which benefited from broader implementation of the Second Generation completion design and extended production history.

Whereas the formal mid-year process undertaken by AMH to select a DrillCo partner utilized a "Trending Type Curve" of 398 MBOE (59% liquids), and a proved reserve type curve of 322 MBOE (79% liquids) BCE was uniquely able to incorporate the current 585 MBOE (70% liquids) type curve into its analysis, allowing BCE to more accurately target returns with its structured offering. Holding all else constant, were BCE to apply the prior 322 MBOE type curve to the existing DrillCo structure, the expected returns would be 17.2% IRR and 1.52x MOIC versus the 24.8% IRR and 1.67x MOIC utilizing the more accurate and current 585 MBOE type curve. To the disadvantage of all the prior competitors in AMH's DrillCo process, BCE utilized this new data to structure and underwrite the transaction to an outsized return relative to the broader market, the prior failed bidder in the AMH process, and the other announced DrillCo transactions.

The higher EURs and larger data set of well production history, coupled with the capped per well AFE exposure, meaningfully de-risked BCE's downside exposure and afforded greater flexibility in the structuring of the DrillCo proposal relative to past proposals in the spring and summer. In meetings with AMH Management in early November 2015, AMH indicated they desired a structure with an upfront promote, dual IRR hurdles and capped upside. BCE indicated a capped upside was not possible; however, several upfront promote and IRR hurdle structures were proposed to AMH. Given the robust initial oil production demonstrated by the Generation 2 wells, BCE was comfortable providing upfront promotes to AMH. This is because the STACK wells are prolific and high-rate in the initial year of production and even in a depressed price environment, the wells are capable of generating IRRs sufficient to trigger reversion to the tail interest and thus materially curtail profit and MOIC. By providing an outsized upfront carry to AMH, DrillCo is capable of generating profit at the 80% and 20% working interest level for an extended period which ultimately enhances MOIC. The larger carry was also made affordable by the capped AFE provision, securing greater certainty of payback. This structure was ultimately crystalized in a Term Sheet on December 1, 2015.

[1] Wells Fargo "High Yield Energy Liquidity Snapshot – Q3 2015" dated November 30, 2015; data excludes companies not subject to redetermination during the fall as well as companies who saw borrowing base increases due to acquisitions (EV Energy Partners and Gulfport Energy).

Investment Merits

Prolific Wells, Resilient Economics

The Company's current type curve for the Subject Acreage has an EUR of ~585 MBoe (~40% Oil, ~30% NGLs, and ~30% Gas) and produces an IRR of ~47% at the 12.24.15 NYMEX Strip. Using the sample of the Company's wells completed with more than 18 fracture stimulation ("frac") stages, and taking an average, the EUR is ~573 MBoe (~55% Oil, ~23% NGLs and ~22% Gas) and produces and IRR of ~63% at the 12.24.15 NYMEX Strip. See the below table for single well economics at various assumed flat oil prices.

Compelling and Resilient Single Well and Program Economics

$3.2MM D&C STACK Mississippian Single Well Economics

	Fall 2015 Type Curve (585 Mboe)			**>18 Frac Stage Actuals (n=41)**		
	IRR	Net PV-10	Months to Payout	IRR	Net PV-10	Months to Payout
12.24.15 Strip	**46.8%**	**$3,524,695**	**25**	**62.7%**	**$4,444,542**	**19**
$35 Flat	24.0%	$1,177,675	38	35.3%	$1,930,563	28
$45 Flat	44.7%	$2,531,674	23	65.5%	$3,590,042	17
$55 Flat	71.8%	$3,885,672	16	106.0%	$5,249,520	12
$65 Flat	106.4%	$5,239,671	12	159.3%	$6,908,999	10
$75 Flat	150.0%	$6,593,669	10	228.5%	$8,568,477	8

Single Well Return Prices	0% IRR	15% IRR	25% IRR	0% IRR	15% IRR	25% IRR
	$19.20	$29.50	$35.60	$18.00	$26.00	$30.80
		30% IRR			30% IRR	
		$38.00			$33.00	

40 Well Structure Return Prices	0% IRR	15% IRR	25% IRR	0% IRR	15% IRR	25% IRR
	$21.35	$36.50	$56.00	$20.25	$32.00	$48.00
		30% IRR			30% IRR	
		$71.40			$61.50	

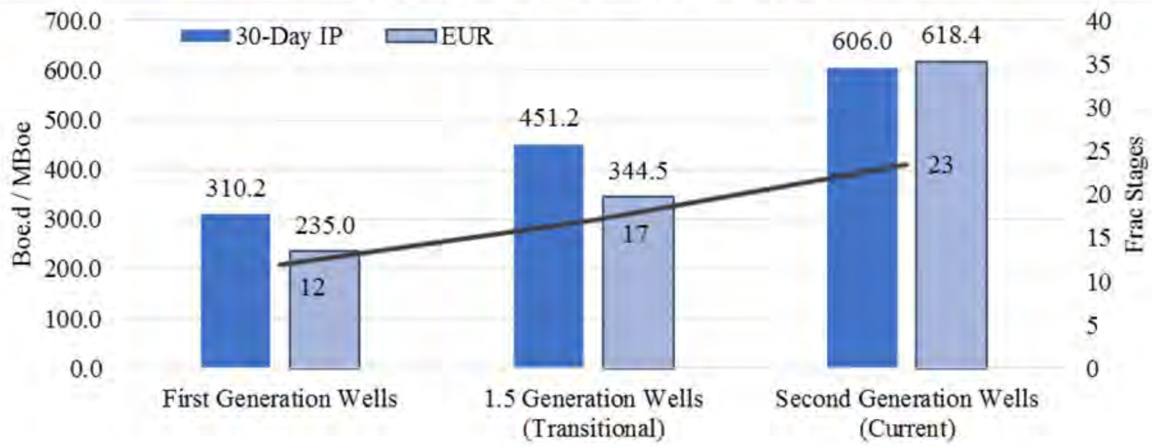
All Flat pricing scenarios utilize $2.50/Mcf Nat Gas
BCE Base Case modeling reflects Fall 2015 Type Curve

Because the majority of AMH's acreage is HBP across historic water-flood units, wells drilled within the units benefit from royalty burdens of generally 12.5% relative to the industry norm of 25.0%. Additionally, the STACK wells benefit by utilizing the existing gathering systems, SWD wells, electricity, and fresh water infrastructure across the units. This reduces upfront costs which typically burden wells in developing plays as well as ongoing lease operating expenses ("LOE"). The all-in LOE of AMH's STACK wells is $5.90 / BOE. Further, the economics will benefit from a gas processing plant currently under construction with an in-service date of April 2016. This plant is physically located on AMH acreage and will provide a $0.75/MCF uplift once online.

Demonstrated Repeatability with Improving Trends

The Company has drilled and completed more than 70 wells on the subject acreage since December 2012, 64 of which targeted the Mississippian. All 64 Mississippian wells have encountered commercially producible hydrocarbons. The Mississippian wells drilled beginning in 2015 took an average of 18 days to drill, with a high of 34 days and a low of 13. These wells have been spread across the Subject Acreage (see detail lease map in Subject Acreage overview) and have confirmed its consistent productivity. The Generation 2.0 wells are performing better and more consistently than the well population as a whole. When comparing wells with > 200' spacing (pre Generation 2.0 wells) to Generation 2.0 wells, there is a meaningful increase in well uniformity with the > 200' spacing wells having a Swanson's mean of 7.54 vs only 2.71 in the Generation 2.0 wells. This tighter distribution of results illustrates that AMH's technical team has effectively honed in on an optimized well design that can consistently produce outstanding investment returns.

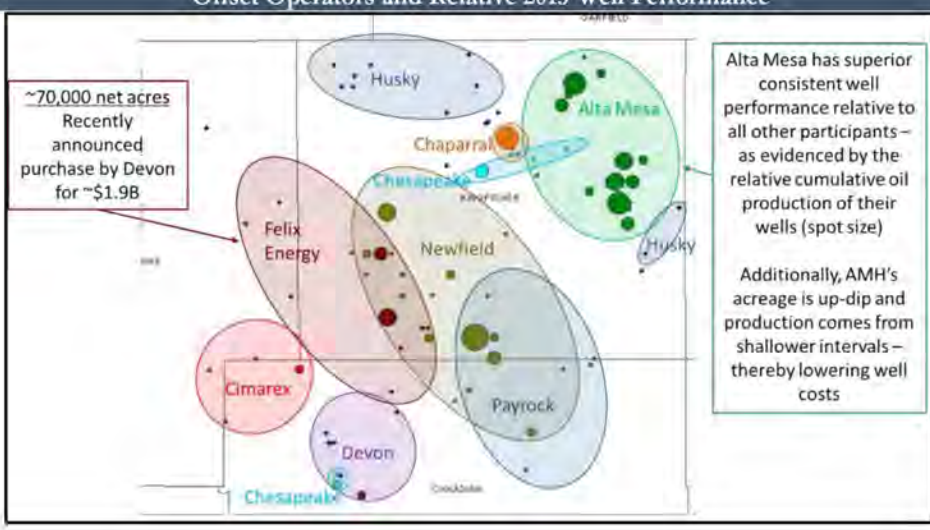
Improving Well Results – Increasing EURs



Experienced Operating Partner

Beyond the Company's recent history of success in the Subject Acreage, AMH has been a successful upstream operator for more than 35 years, developing fields with a variety of distinct geological settings and petrophysical characteristics. The Company has possessed the Subject Acreage for more than 20 years, and has a thorough understanding of the subsurface. The Company has a demonstrated trend of reducing drill times, lowering well costs and improving completions on the Subject Acreage.

Offset Operators and Relative 2015 Well Performance



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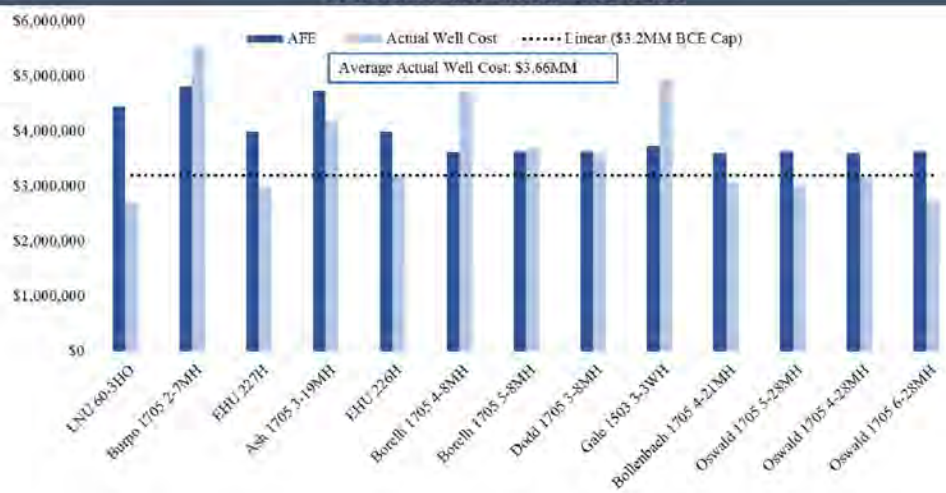
Capped Capital Exposure

BCE was able to successfully negotiate a cap on its per well capital exposure at $3.2 million per well. This means that the Company will pay 100% of the well costs above $3.2 million. Similarly, if the Company achieves further per well cost reductions, BCE's capital burden will be reduced. Notwithstanding, the $3.2 million per well cap, DrillCo may incur additional costs of up to $150,000 / well for specific agreed to changes in well development or completion design. AMH has rigorously and consistently improved its completion design and performance with tighter frac spacing, and BCE wants to ensure that its Development Wells utilize the best practices of the "current Generation" of well design. These costs will only be applied to DrillCo wells if they are verifiably and consistently being incurred by wells drilled by AMH which DrillCo does not participate in. Every scenario BCE has modeled assumes that the full $3.2 million per well is invested, and thus BCE's modeled returns are fully risked with regards to capital costs.

2015 AFEs and Actual Well Costs



JDA Exclusive Period – Expansion Optionality under the Same Terms

Under the terms of the JDA, BCE will be the Company's sole financial development partner in the Subject Acreage for a period of 4 years following the execution of the JDA. The initial two committed tranches are estimated to take approximately a year to drill under the currently contemplated rig schedule. The JDA provides for the expansion of the scope of DrillCo in incremental 20 well tranches, subject to mutual agreement. BCE is not underwriting the investment to more than 40 wells, however, it should be noted that the addition of subsequent tranches is highly accretive to the returns achieved at DrillCo, as the capital required for the later tranches can be funded in whole or in part by the proceeds from the production of the earlier tranches, allowing DrillCo and BCE to achieve superior multiples on its invested capital ("MOIC").

Expansion Enhances Returns – Unlevered Base Case Assumptions				
DrillCo Return ($ in MM)	**40 wells**	**60 wells**	**80 wells**	**100 wells**
DrillCo PV10	$26.8	$40.3	$53.6	$66.3
PV10 as % of Total Project PV10	20%	20%	20%	21%
DrillCo CAPEX	$128.0	$192.0	$256.0	$320.0
DrillCo Max Cash Outflow	$98.2	$124.5	$138.7	$141.9
DrillCo IRR	**24.4%**	**25.2%**	**26.0%**	**26.6%**
DrillCo MOIC	**1.65x**	**1.77x**	**1.91x**	**2.11x**
DrillCo Profit	**$64.0**	**$95.7**	**$126.7**	**$157.3**

BCE LP Return ($ in MM)	40 wells	60 wells	80 wells	100 wells
Fund Max Cash Outflow	$37.5	$37.5	$37.5	$37.5
Fund IRR	**29.9%**	**33.5%**	**35.9%**	**37.1%**
Fund MOIC	**1.93x**	**2.26x**	**2.59x**	**2.96x**
Fund Profit	**$34.9**	**$47.2**	**$59.8**	**$73.6**

Well-Established Operating Environment and Existing Infrastructure

The Subject Acreage is located in the heart of what is known as the Sooner Trend, a productive region encompassing hundreds of conventional oil fields exploited as early as the 1950s. Now, the region is experiencing a renaissance of enhanced activity as the prolific nature of the STACK as an unconventional resource is revealed and more and more operators compete to secure a sizable acreage position. Accordingly, important features of infrastructure necessary to ensure continuous and profitable oilfield operations are in place and readily accessible, including roads, electricity, hydrocarbon gathering, right of ways, freshwater sourcing, and produced water handling and disposal.

Of note, ~50,000 of AMH's acreage is comprised of four historic waterflood units. The units have been densely drilled on a defined pattern down to 80 acre spacing. Thus across the entire footprint of these units there is a system of water distribution which has historically served the waterflood and can now serve the horizontal STACK wells as well. Up to 2,500 barrels per day of produced water from the STACK wells go directly into the waterflood at no cost to AMH. All additional disposed water travels via pipe across the existing water infrastructure into three SWD wells AMH owns. As an aside, the AMH acreage is situated west of the Nemaha Ridge which the Oklahoma Corporation Commission defines as outside of the earthquake zone. Thus the AMH SWD system is not threatened for curtailment or shut-in as part of the state's broader response to increasing seismic activity in the central and northeastern portions of Oklahoma.

Additionally, AMH has proactively addressed concerns with procuring ample fresh water for large zipper frac operations on multi-well pads. Each well frac'd requires on the order of 350,000 barrels of water and with AMH regularly conducting drilling of 4-6 wells on a single pad, zipper frac operations could require in excess of 2,000,000 barrels of water. AMH has eliminated the costs, logistical impediments and inefficiencies resulting from the need to continuously source water by purchasing frontage acreage along the Cimarron River which traverses its STACK position. The Cimarron River is a salty watershed and therefore cannot be used for cattle or agricultural purposes; thus, there are no commercial restrictions on the use of water by those who own surface acreage along its banks. AMH is able to pull an unlimited water from the Cimarron for free, which it uses to fill its >3,000,000 barrels of water storage. This water can then leverage off of the existing backbone of infrastructure to cheaply be moved across the units.

Dedicated Hydrocarbon Gathering, Processing, and Marketing

In addition to the established regional infrastructure, the Subject Acreage will benefit from an expanded and enhanced dedicated gathering, processing and marketing solution beginning in the spring of 2016. This new dedicated system and plant will enhance economics and ensure scalable takeaway capacity and marketing in a play that is aggressively being developed and could otherwise become bottlenecked.

Elegant Investment Structure

BCE's negotiated investment structure has been refined over months of dialogue with the Company, and analysis by BCE's investment professionals. The structure has been tailored to provide exceptional risk adjusted returns, with regards to IRR, MOIC and absolute profit across a variety of possible outcomes pertaining to well performance, commodity prices, pace of execution of the campaign, or the purchase of the Subject Acreage or the Company by a third party. An important feature common to the drilling partnership structure is the recyclability of cashflows from production into subsequent capital expenditures, reducing the total investment required from the fund, and enhancing returns. The dual IRR hurdles ensure that DrillCo participates in the early years of the wells production at a high working interest level before reverting into the Final Reversionary Interest after a 25% IRR is achieved. The STACK wells are prolific and high-rate in the initial year of production and even in a depressed price environment, the wells are capable of generating IRRs sufficient to trigger reversion to the tail interest and thus materially curtail profit and MOIC. By providing an outsized upfront carry to AMH, DrillCo is capable of generating profit at the 80% and 20% working interest level for an extended period which ultimately enhances MOIC.

Because BCE will receive real working interest ownership in each wellbore as well as cash flows from the producing wells, there are multiple means to enhance returns from utilizing leverage. A traditional reserves based lending facility will likely be utilized within the first 3 months of production coming online. BCE is currently in discussion with Wells Fargo regarding a credit facility for DrillCo. As modeled, BCE production will exceed 2,000 BOED net by July 2016 and grow to over 8,000 BOED net by April 2017. This level of production (accounting for the reversion to the tail interest) should support a credit facility of at least $30.0 million which BCE will quickly be able to utilize. It is important to note that the economic returns shown throughout this memo do not consider leverage.

Leverage Enhances Returns – Base Case Assumptions (40 wells) – DrillCo Level

DrillCo Unlevered Return ($ in MM)		Debt Funding Option		DrillCo Levered Return ($MM)	
DrillCo PV10	$26.8	Tranche 1 Principal	$15.0	DrillCo CAPEX	$128.0
PV10 as % of Total Project PV10	21%	Tranche 1 Interest Rate	3.0%	Leverage Utilized	$30.0
DrillCo CAPEX	$128.0	Tranche 1 Draw Date	7/1/2016	DrillCo Equity Investment	$68.2
DrillCo Max Cash Outflow	$98.2	Tranche 1 Max Term (Months)	36	**Equity IRR**	**26.5%**
DrillCo IRR	**24.4%**	Tranche 2 Principal	$15.0	**Equity MOIC**	**1.93x**
DrillCo MOIC	**1.65x**	Tranche 2 Interest Rate	3.0%	**Equity Profit**	**$63.3**
DrillCo Profit	**$64.0**	Tranche 2 Draw Date	11/1/2016		
		Tranche 2 Max Term (Months)	36		

Leverage Enhances Returns – Base Case Assumptions – DrillCo Equity Level

Within DrillCo Equity Split (Fund | Co-Invest)			
Fund MOIC	**2.15x**	Co-Invest MOIC	**1.66x**
Fund IRR	**30%**	Co-Invest IRR	**22%**
Fund Investment	($37.5)	Co-Invest Investment	($30.7)
Fund Profit	**$43.1**	Co-Invest Profit	**$20.3**

<u>Investment Risks & Identified Mitigants</u>

Prolonged Low Commodity Price Environment

There remains a great deal of uncertainty with regards to the future of commodity prices. Low oil, NGL and natural gas prices necessarily limit the profitability of oil and gas producing operations, and at some point make new development, such as drilling and completing new wells, uneconomic. Investing wisely in oil and gas assets at low oil prices with future uncertainty requires a diligent focus on the only the best assets and the most insulating structures and situations.

<u>Mitigants:</u> BCE's structure has been crafted so that compelling returns are preserved even in a sustained low price environment. This is achieved via the tiered working interest sharing and cap on capex dollars. In a sustained low price environment wherein cash flows from production are hampered, BCE's wellbore interest will remain larger for longer, as the achievement of the hurdle IRRs on DrillCo's invested capital take longer to achieve. As the achievement of the target IRRs take longer, the absolute return and thereby MOIC and profit required to achieve the requisite IRRs is increased, leading to larger profits and MOICs in the long run. If commodity prices recover quickly, BCE targeted IRR of

25% will be achieved more readily. At either end of the pricing spectrum, the structure will produce excellent risk adjusted returns, in consideration of IRR, MOIC and profit.

Program Returns at Sustained Low Crude Oil Price Levels

Unlevered Base Case DrillCo Returns Under Different Pricing Scenarios

	$30.00	$35.00	$40.00	$45.00	$50.00	12.24.15 Strip	Escalating	Custom
IRR	9.7%	17.3%	18.2%	20.9%	24.0%	24.4%	25.2%	27.1%
MOIC	1.3x	1.6x	1.5x	1.6x	1.6x	1.7x	1.7x	1.8x
Profit ($MM)	$33.8	$60.9	$54.8	$54.7	$55.7	$64.0	$67.8	$75.3

12.24.15

NYMEX Strip Average Prices

	2016	2017	2018	2019	2020	2021	2022
Oil	$40.95	$46.17	$49.32	$51.77	$53.39	$54.43	$55.00
Gas	$2.31	$2.73	$2.89	$3.02	$3.17	$3.30	$3.43

Escalating Srip Average Prices

	2016	2017	2018	2019	2020	2021	2022
Oil	$40.95	$46.17	$49.32	$51.77	$53.39	$54.43	$55.61
Gas	$2.31	$2.73	$2.89	$3.02	$3.17	$3.30	$3.67

Custom Strip Average Prices

	2016	2017	2018	2019	2020	2021	2022
Oil	$37.82	$45.00	$55.00	$65.00	$75.00	$75.00	$75.00
Gas	$2.31	$2.73	$2.89	$3.02	$3.17	$3.30	$3.43

Drainage from Downspacing

As the Company continues to develop the Subject Acreage, the average spacing between wells will naturally decrease. The risk exists that if the Company chose to drill a well in proximity to a well in which DrillCo was participating, the offset well could deplete the hydrocarbons from the same drainage area as the DrillCo well.

Mitigants: This contingency is addressed within the JDA, and the Company will not be permitted to drill wells within a certain spacing limit of DrillCo wells so as to eliminate the risk of offset drainage or two wells competing for the same hydrocarbons. BCE and AMH must mutually agree to the Development Plans, and each Development Plan must set forth, among other things, the completion design, drainage and spacing plans for wells, including those drilled outside of DrillCo. DrillCo's sole discretion regarding the acceptance of any development plan (including specifications regarding well spacing) effectively eliminates this risk.

Moral Hazard of the Company's Operations Outside of DrillCo

AMH will retain the ability to drill wells in the Subject Acreage outside of the JDA. Given the Company's increased ownership in these non-JDA wells, the risk exists that the Company will cherry pick the best locations and / or conduct the best operations on non-JDA wells, and deliver marginal well locations or operations to JDA wells.

Mitigants: DrillCo may approve or reject, in its sole discretion, each Development Plan and budget submitted to it by the Company. Furthermore, an operating committee will be established that will meet quarterly to hold planning sessions and review performance. The operating committee will include equal representation from the Company and BCE and will share technical evaluations, historical and forecasted development results, discuss future development operations and plans on the Subject Acreage. Additionally, the Drilling Partnership structure protects against this risk, as the economic hurdles are measured across a tranche of 20 wells (rather than on a well-by-well basis), ensuring that the Company is incentivized to provide locations and operations to DrillCo that can deliver the requisite economics in order to trigger tranche reversion.

Early Monetization of Assets

The Company could choose to monetize the subject acreage before the expiration of the JDA, potentially limiting DrillCo's return depending on the terms of the sale to which it was subject.

Mitigants: The Company will not be able to force DrillCo into a sale of its interests, unless certain minimum return thresholds are achieved, namely the greater of a 2.0x MOIC or a 25% IRR on the entire tranche. The last part of the previous sentence is important: the "on the entire tranche" drag concept guarantees that we are able to achieve a double on at least $128mm of outlaid capital in a company monetization event. Additionally, should it so choose, DrillCo will be able to sell its interests alongside those of the Company upon the same terms in the event of a sale.

Development Committee Disagreements

Although the parties are substantially aligned given the economic parameters of the JDA, the potential exists for there to be disagreement between the parties concerning the continued development of the Subject Acreage under the JDA. Ongoing disagreements could meaningfully delay the deployment of capital and even lead to the early termination of the JDA.

Mitigant: The JDA is constructed so that neither party can drag the other into the continuation of the joint development program. That being said, the structure and terms of the JDA should substantially align the interests of both parties, as their economic returns are positively correlated. That is, any adjustment or achievement that enhances DrillCo's return in terms of IRR, will also enhance the Company's return. Improvements in drilling practice or completion design that improve recoveries or reduce costs will benefit the interests of both parties participating in a JDA. Further, no capital will be outlaid until there is complete agreement on well locations, rig schedules and completion designs taking much of the risk associated with deploying capital in suboptimal operations in suboptimal locations off the table.

II. Company & Asset Overviews

Alta Mesa Holdings, LP

Alta Mesa Holdings, LP is a privately held independent oil and gas exploration and production company headquartered in Houston, TX with primary operations in the STACK play of Oklahoma, and South Louisiana. AMH is focused on maximizing the profitability of its assets in a safe and environmentally sound manner, by applying advanced engineering analyses and enhanced geological techniques to under-developed or over-looked conventional resource areas to create long term value.

The Company is led by Hal Chappelle, who serves as the President and Chief Executive Officer. Mr. Chappelle joined Alta Mesa as President and CEO in November 2004. He has over 25 years in field operations, engineering, management, marketing and trading, acquisitions and divestitures, and field re-development in collaboration with majors including Exxon and Chevron. He has worked for Louisiana Land & Exploration Company, Burlington Resources, Southern Company, and Mirant. Mr. Chappelle retired as a Commander from the U.S. Navy Reserve. He has a Bachelor of Chemical Engineering from Auburn University and a Master of Science in Petroleum Engineering from The University of Texas at Austin.

Mike Ellis is Founder, Chairman and Chief Operating Officer. Mr. Ellis founded Alta Mesa in 1987 after beginning his career with Amoco, and is Chairman and Chief Operating Officer. Mr. Ellis manages all day-to-day engineering and field operations of Alta Mesa. He has over 30 years' experience in management, engineering, exploration, and acquisitions and divestitures in the Gulf Coast, Midcontinent and West Texas regions. He has a Bachelor of Science in Civil Engineering from West Virginia University, where he is an active member of the Visiting Committee of Petroleum Engineering.

Mike McCabe serves as Vice President and Chief Financial Officer. Mr. McCabe joined Alta Mesa in September 2006. Mr. McCabe has over 25 years of corporate finance experience, with a focus on the energy industry. He has served in senior positions with Bank of Tokyo, Bank of New England, and Key Bank. Mr. McCabe holds a B.S. in Chemistry and Physics from Bridgewater State College, a M.S. in Chemical Engineering from Purdue University and an M.B.A. in Financial Management from Pace University.

Gene Cole joined AMH in 2007 and currently serves in the position of Vice President and Chief Technical Officer. Mr. Cole has over 25 years of extensive domestic and international oilfield experience in management, well completions, well stimulation design and execution. He started his career with Schlumberger Dowell as a Field Engineer and served in numerous increasingly responsible positions with Schlumberger in the areas of field operations, engineering and management. He has a Bachelor of Science in Petroleum Engineering from Marietta College.

AMH has successfully operated for over 35 years and has publicly traded debt and thus has audited financial statements, third party reserve engineering reports and well-established corporate governance, internal controls and procedures.

AMH in the STACK

Under the guidance of Mike Ellis, AMH acquired its position in the STACK beginning in 1991. Mr. Ellis began buying small non-operated acreage within large water-flood units operated by Conoco, Texaco and Exxon with the expectation that they would ultimately exit the plays and AMH would be uniquely situated to acquire their positions. As this thesis played out, AMH came to own and operate over 40,000 net acres across what is now the lynch-pin of their STACK position. AMH drilled a minimal amount of wells over the ensuring 20 years, focusing instead on maintaining production levels through waterflood expansion and implementing new waterfloods in unitized zones.

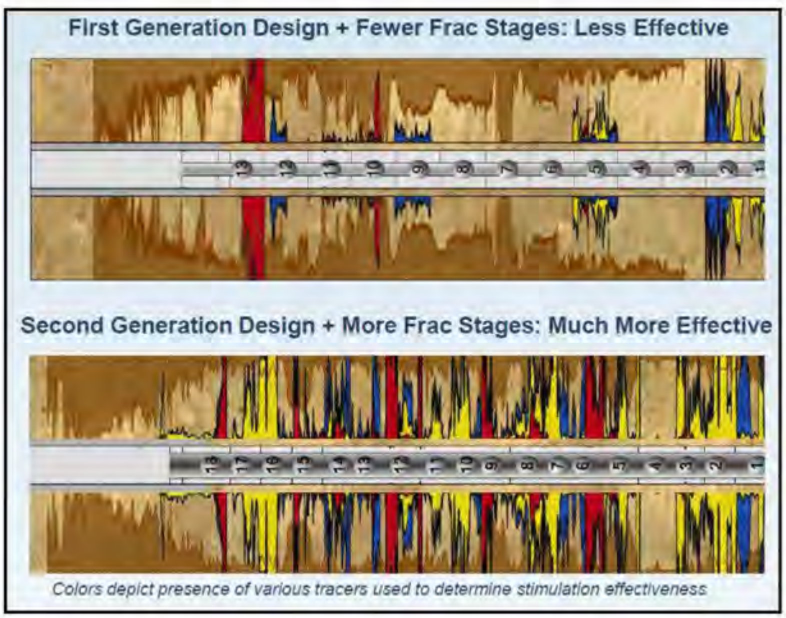
With prices exceeding $100/Bbl in early 2011, AMH began a vertical infill program which ultimately led to 25 wells being drilled over the ensuing 2 years. These wells were 40 acre infills and generated a tremendous amount of new data for AMH. AMH deliberately drilled wells down to the Viola formation which is the deepest known pay in the region, below the Meramec, Woodford and Hunton formations. AMH systematically completed and tested each zone within the well to understand the potential of each pay and utilized chemical chromatography, or oil fingerprinting, which allowed unitized and non-unitized formations to be co-mingled and produced in a single well-string.

The fingerprint data consistently indicated that the Mississippian formation was the most productive, and contrary to initial expectations, was not depleted. Throughout the vertical development program, AMH was forced to drill infill wells off-pattern due to land and regulatory delays, and the best results were surprisingly seen in the off-pattern wells. This led AMH to uncover that wells had east to west communication which not coincidentally aligned with the natural east to west fracture orientation. AMH Management therefore believed there was a tremendous amount of oil remaining in the spaces between the infill wells which could be exploited through horizontals with tight completion spacing.

Confident in their findings, AMH spud their first horizontal STACK lower Mississippian well on December 1, 2012 with the expectation of achieving 150 MBOE per well. A second well was drilled immediately thereafter, followed by a six-month cessation of activity while AMH assessed the production of these initial pilot wells. The results of these initial wells exceeded AMH's expectations with the wells achieving peak 30 day initial production ("30 day IPs") and EURs of 311 BOED / 565 BOED and 322 MBOE / 271 MBOE respectively. These wells had 12 stage completions with 350' between completion stages.

AMH began a one-rig development program in mid-2013 which was designed to systematically make adjustments to well completion technique in order to determine the most effective completion method. Specifically, AMH completed each individual stage with stage specific grains of sand coated with radioactive tracers. This allowed AMH to understand which zones were being completed successfully and how far into the formation the fracs were reaching. The initial completion design utilized a ball and sleeve design. Consistently, AMH noticed that the sleeves were not opening as designed and therefore not all stages were being stimulated. Across the initial 6 wells drilled by AMH ("Generation 1.0") there were several instances in which only 4-6 stages were adequately treated based on the tracer surveys and pressure analysis collected for each stage.

Frac Design Progression – More Stages, More Effective Stimulation of the Lateral



<u>Technical Refinements</u>

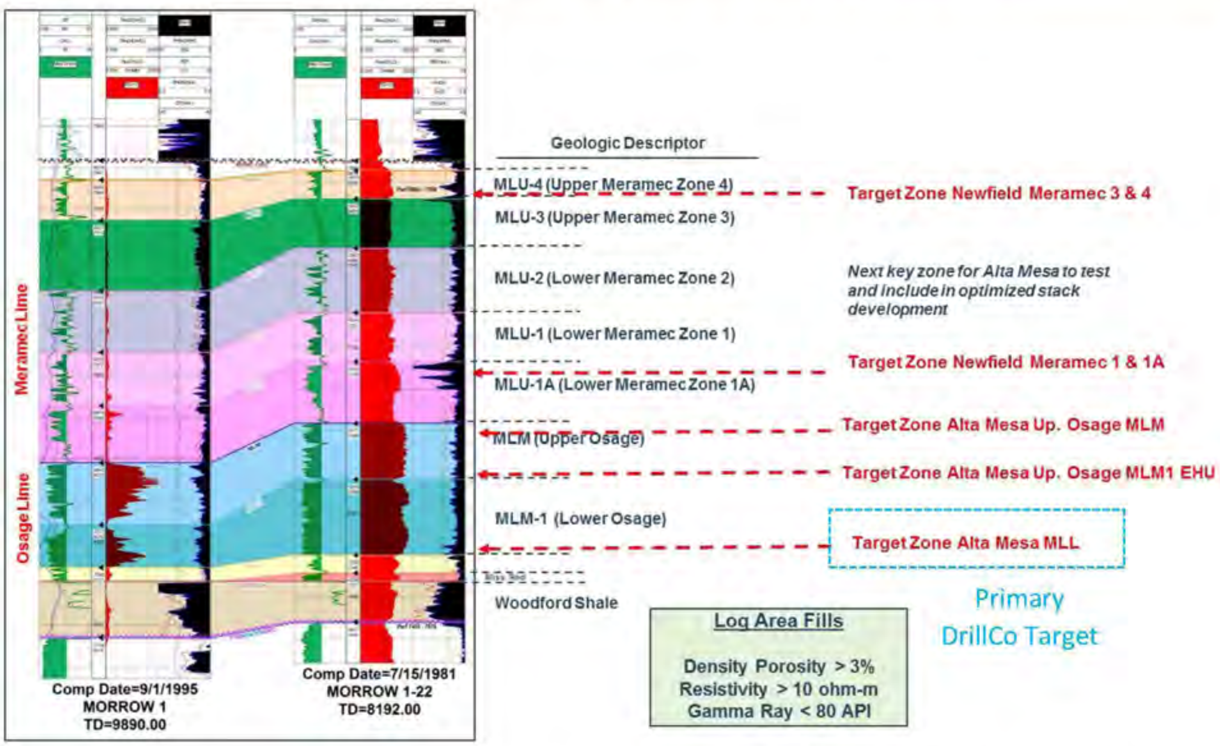
Generation 1.0 findings led AMH to change their completion design from the ineffective balls and sleeves to plug and perf with swellable packers. The next 7 wells drilled ("Generation 1.5") utilized the different completion design and had an average of 17 completion stages. In order to have results which were comparable to Generation 1.0, Generation 1.5 wells used the same volume of sand per completion stage. AMH found that they were able to achieve good isolation per stage and achieved more consistent results.

Improving Results while Maintaining Low Well Costs

	First Generation Wells	1.5 Generation Wells (Transitional)	Second Generation Wells (Current)	*Second Generation Relative to First Generation*
Spud Dates (Development Initiated)	Dec. 2012 - Sept. 2013	Sept. 2013 - Jan. 2014	**Jan. 2014 - Present**	-
Number of Wells in Sample	6	7	**46**	-
Mean Expected Well Cost (AFE)	$3,674,750	$3,820,129	**$3,762,915**	*1.0x*
Mean Actual Well Cost	$4,160,513	$4,379,503	**$4,158,786**	*1.0x*
Mean Days to Drill	40	36	**23**	***0.6x***
Mean Fracture Stimulation Stages	12	17	**23**	*2.0x*
Mean 30-Day Peak Rate (Boe/d)	310.2	451.2	**606.0**	***2.0x***
Mean Estimated Ultimate Recovery (Mboe)	235.0	344.5	**618.4**	***2.6x***

As AMH became confident in its ability to isolate zones with the swellable packers and to efficiently treat each frac zone, they progressively began to decrease the completion spacing from >300' to densities of less than 200'. Beginning in January 2014, the Company began its Generation 2.0 development program which currently utilizes ~26 frac stages and incorporates learnings from the earlier vertical development program which significantly aid in the landing of the lateral and geo-steering.

Stacked Target Intervals – AMH Exploits its Thicker Osage Lime Section



The oil finger printing and meticulous completion testing of the vertical program which AMH undertook through 2012 ultimately indicated to AMH that they should land their laterals in the Osage Lime; whereas, the majority of offsetting operators land their laterals in the upper portion of the Meramec Lime due to depletion fears. The vertical program had informed AMH that the entire >500' thick Lower Mississippian column was equally depleted and had a quick water decline; therefore, consistent with normal E&P activity, the formation should be developed from the bottom zone up. Additionally, AMH had run numerous Schlumberger mechanical property logs during their vertical program which ultimately helped correlate a zone of high porosity across the field which AMH geo-steers its wells through.

Alta Mesa Recovers More for Less than the Other STACK Operators

Operations / **Inventory**

Company	# Wells	Average Lateral, ft	EUR MBOE	EUR per 1,000 ft	Well Cost $MM	Well Cost Per 1,000 ft	Acres	Locations Risked	Locations Unrisked
Newfield	45	9,919	950	96	7,500	756	225,000		4,150
Devon(Felix)	15	10,000	1,000	100	8,000	800	80,000	1,400	3,000
Alta Mesa	29	4,375	620	142	3.200	731	80,000	1,750	4,750

Production Rates

Company	# Wells	30-Day Rate BOE/d	30-Day per 1,000 ft BOE/d	30-Day % Oil	60-Day Rate BOE/d	60-Day per 1,000 ft BOE/d	60-Day % Oil	90-Day Rate BOE/d	90-Day per 1,000 ft BOE/d	90-Day % Oil
Newfield	45	930	94	77	829	84	73	785	79	69
Devon(Felix)	15	1,100	110	45						
Alta Mesa	29	573	131	75	528	121	74	491	112	72

<u>**Subject Acreage Overview**</u>

The Subject Acreage consists of ~80,000 net lease acres in Northern and Eastern Kingfisher County, Oklahoma, 50,000 net acres of which are held by production ("HBP"). AMH began acquiring this leasehold in 1991 and generally speaking, the leases are situated in and among large mature oil fields with multiple pay zones at depths from less than 2,000 feet to 8,000 feet. The assets have been predominately shallow-decline, long-lived oil fields originally developed on 80-acre vertical well spacing and subsequently water flooded to further hydrocarbon recovery. This historical conventional development is now being replaced by modern unconventional development techniques including horizontal drilling and hydraulic fracturing.

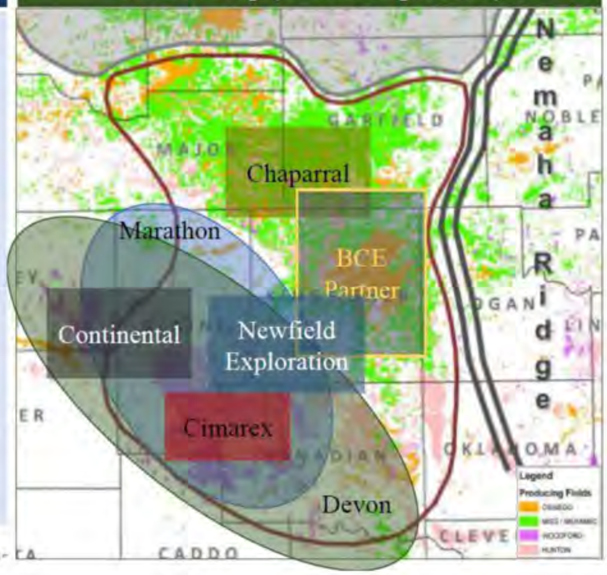
STACK Overview

The Core STACK of Kingfisher, Garfield, and Canadian Counties, OK is a World-Class Unconventional Hydrocarbon Resource

Overview

- The **Sooner-Trend-Anadarko-Canadian-Kingfisher ("STACK")** play is located to the west and northwest of Oklahoma City in central Oklahoma
  - Kingfisher County is the focus of the majority of industry activity
  - Numerous private and public operators are now accelerating their delineation and/or development of this relatively new unconventional play (first delineated in 2013) following highly promising industry results
  - Active operators include Devon, Marathon, Chesapeake, Newfield and Cimarex, among others
  - BCE's Partner had an early mover advantage, with legacy assets in the region overlaying what become the core of the play
- **Several hundred feet thick oil-saturated hydrocarbon column**
  - The organic rich Woodford Shale underlies the Mississippian section (including the most prolific Meramec interval) and is the primary source rock
  - Oil is trapped by impermeable shales above and Nemaha Ridge to the east
  - Multiple productive targets including Oswego, Meramec, Osage, Hunton, and Woodford

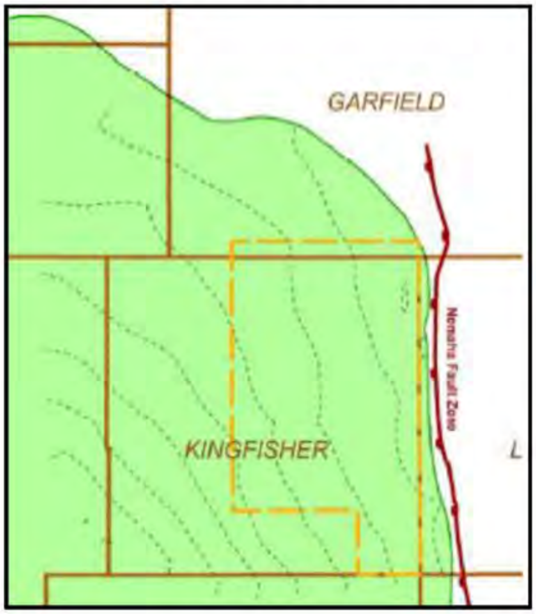
STACK Map (w/ select Operators)

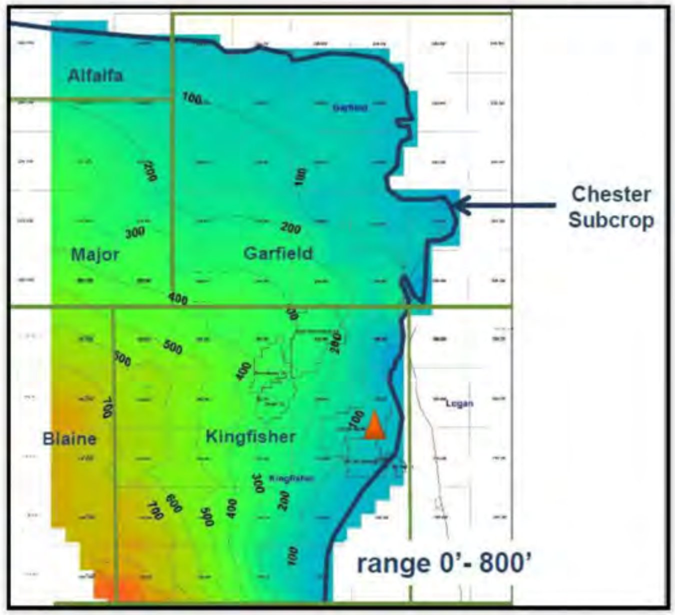


Sources: Chaparral Energy; Morgan Stanley Research "Oklahoma Resource: The Next Great American Play(s)"

The Nemaha Ridge is a large regional feature which runs from Kansas through Oklahoma and plays an important role in the trapping of hydrocarbons and creation of faulting and natural fractures. Orientation and proximity to the Nemaha Ridge is critical to the economic success of Mississippian wells, with better reservoirs and fracturing occurring to the west of the Nemaha, which is where the AMH position falls. In Kingfisher, the Mississippian section is on average around 600-ft thick relative to 300-ft thick in Logan County which is on the immediate east of the Nemaha Ridge. The thick Mississippian section and natural fracturing which occurs as you approach the Nemaha Ridge make the AMH acreage uniquely situated from a geologic perspective.

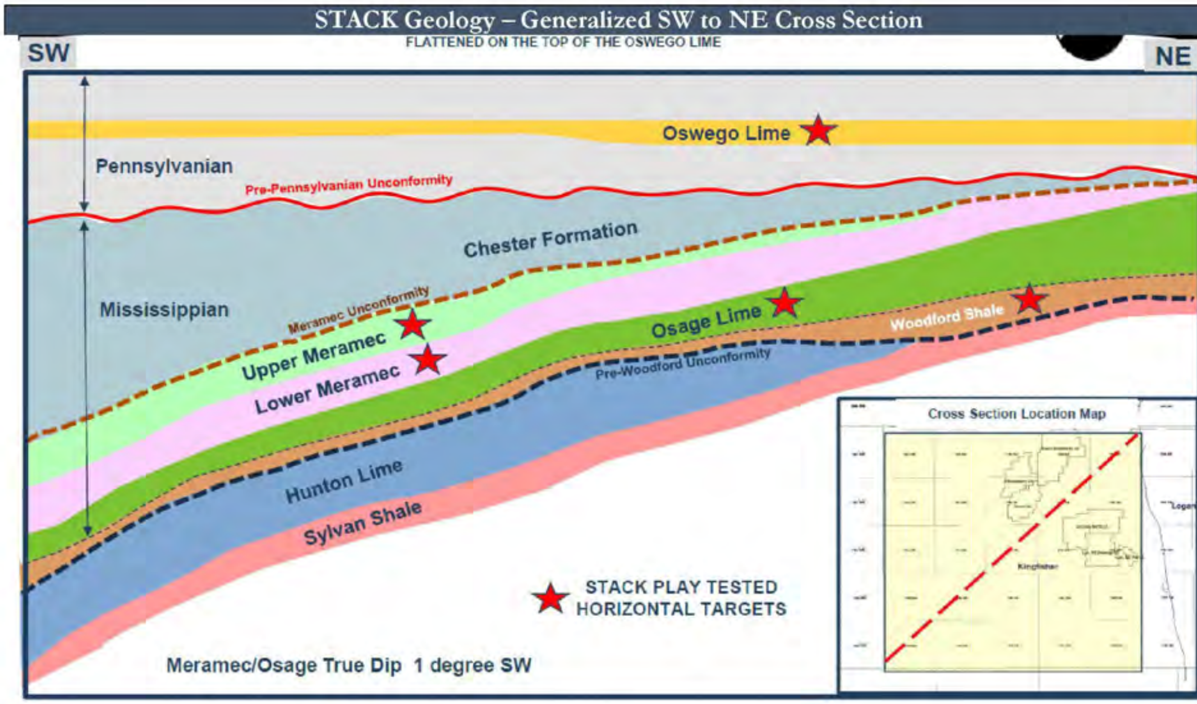
STACK Geology – Favorably Positioned to West of Nemaha Ridge and Overlaid by Chester Shale





The Meramec and Osage sections of Mississippian are siliceous, naturally fractured due to their proximity to the Nemaha Ridge, and overlain by the Chester Shale. Unlike in the northern portion of Oklahoma which is characterized by high water cuts, the Chester Shale overlays the Mississippian age rock in Kingfisher County and acts as a barrier to keep the Pennsylvanian seas from flooding the Mississippi Lime. As a result water cuts are 1:1 in North East Kingfisher versus oftentimes > 100:1 in areas without the Chester Shale. Also important, the Chester Shale serves as a natural frac barrier so frac jobs do not propagate upward into water bearing formations.

STACK Geology – Generalized SW to NE Cross Section



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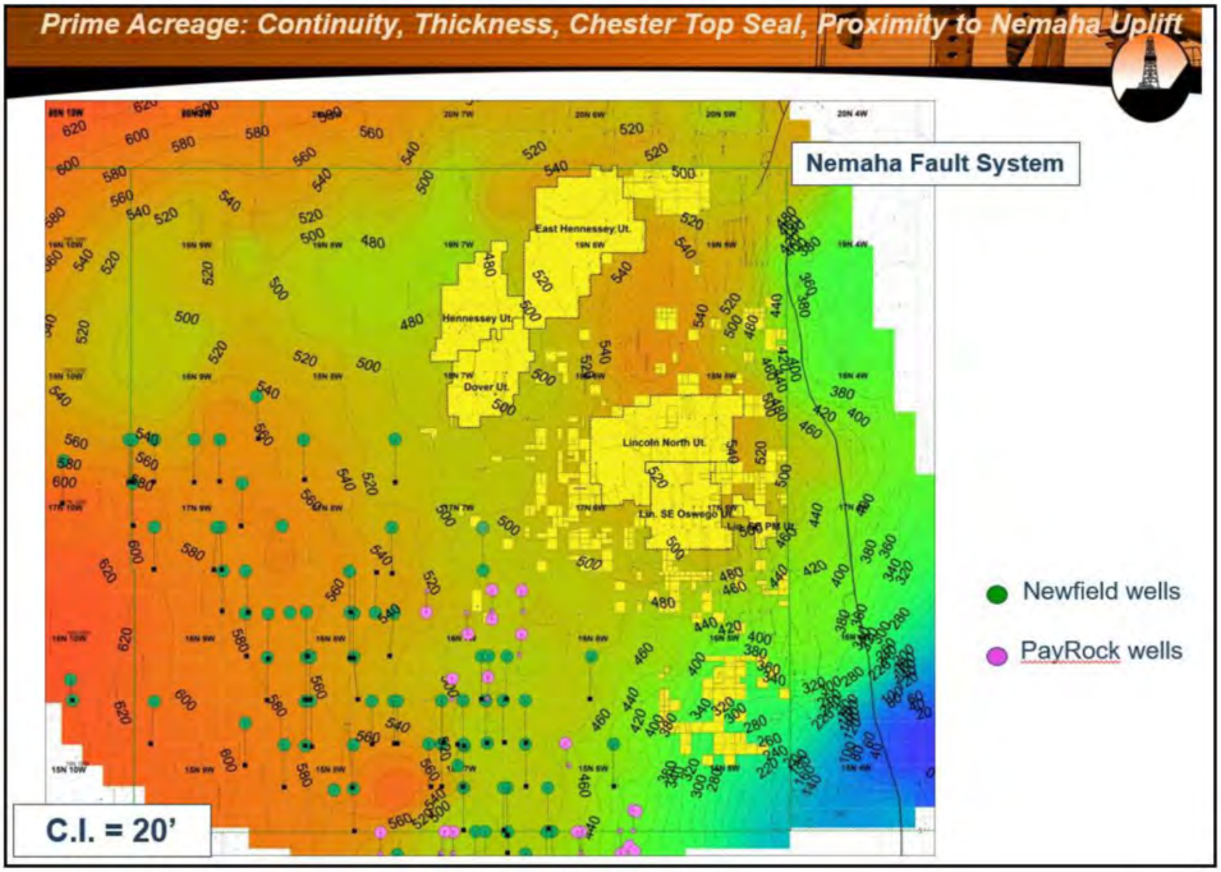
Lower Miss Lime (Osage & Meramec) Gross Thickness across Kingfisher - ~500 feet of Oil-Saturated Rock



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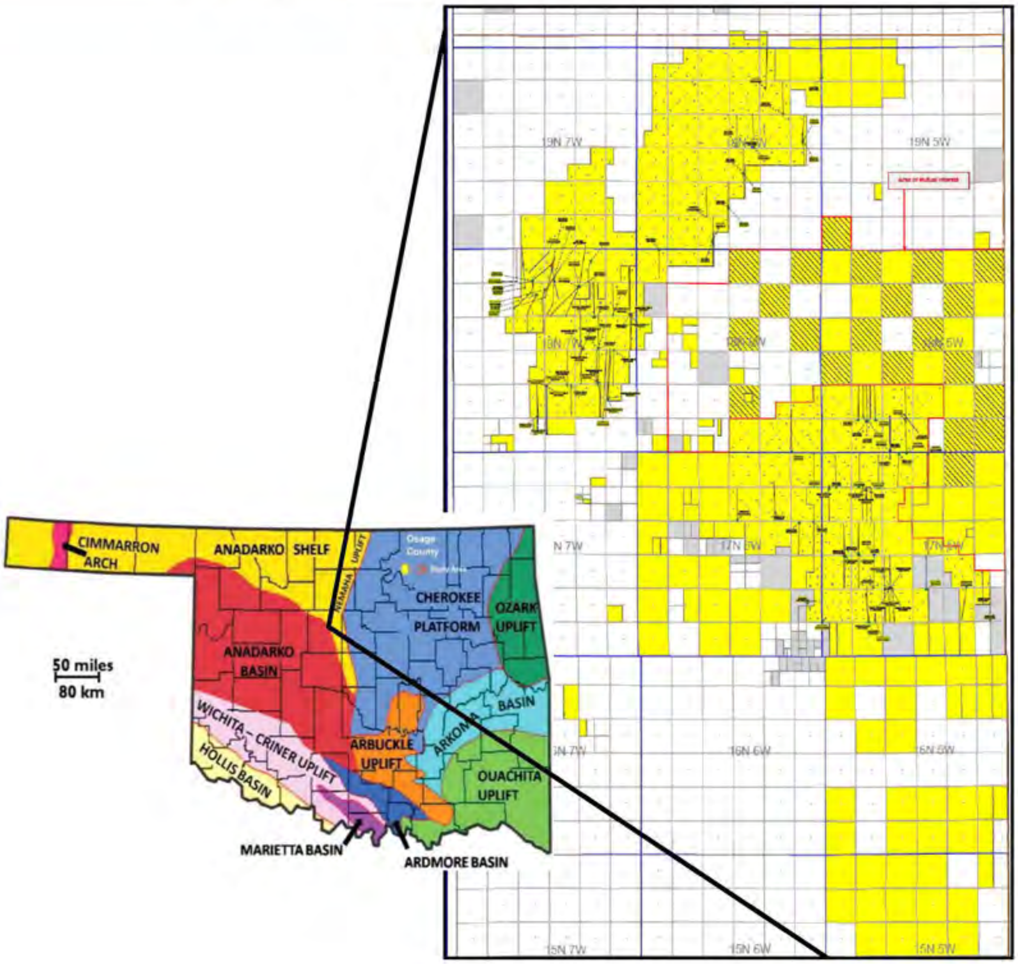
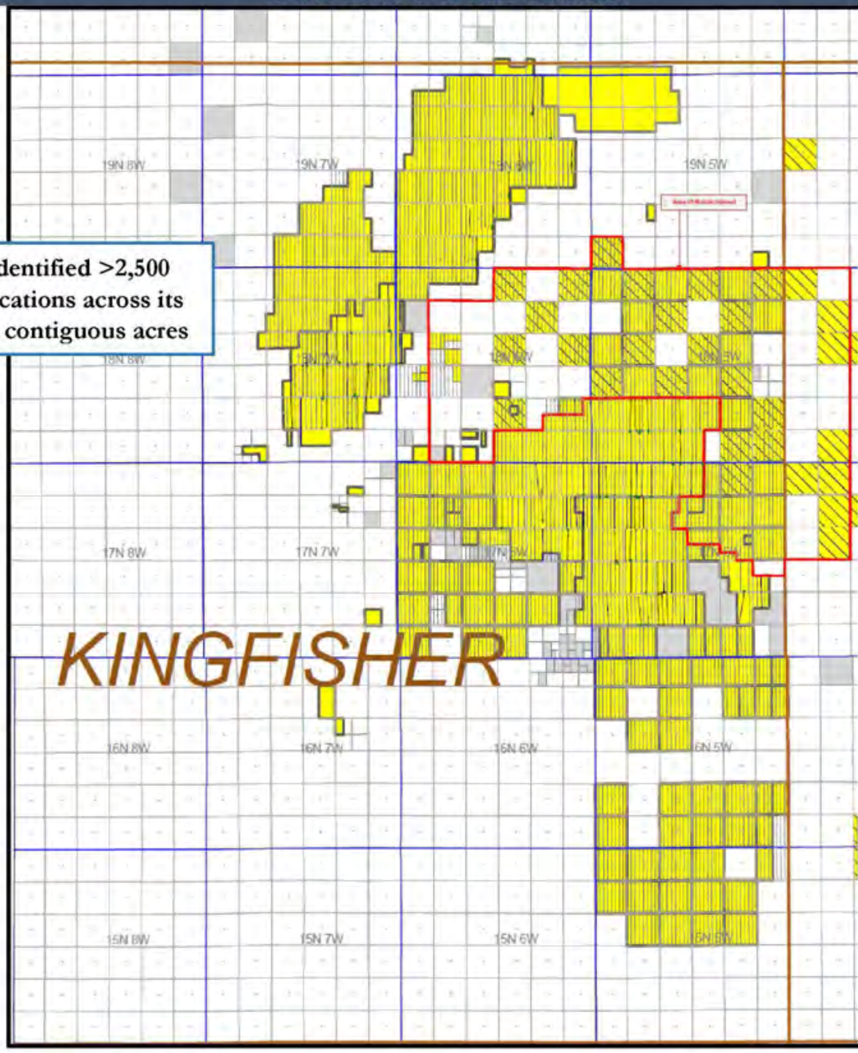
AMH Leasehold in the STACK of Kingfisher County



Lease Detail with Well Locations

AMH has identified >2,500 horizontal locations across its 80,000 highly contiguous acres



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III. Initial Development Plans

Consistent with the terms of the JDA, AMH must provide comprehensive information regarding the proposed Joint Wells and the associated operations. These details make up the Development Plans, which are subject to DrillCo's review and approval before DrillCo is obligated to fund costs associated with any Joint Wells under the Development Plan.

Below are some pertinent items from the preliminary Development Plan delivered to DrillCo for approval before proceeding to closing on the initial two 20 well tranches, and the funding of the initial AFEs and associated capital calls provided thereunder.

Wells labeled as Substitute can be selected by DrillCo to replace wells currently included in Tranches 1 and 2.

See "DrillCo and the Joint Development Agreement ("JDA")" in the Transaction Review section for more context on the Development Plans.

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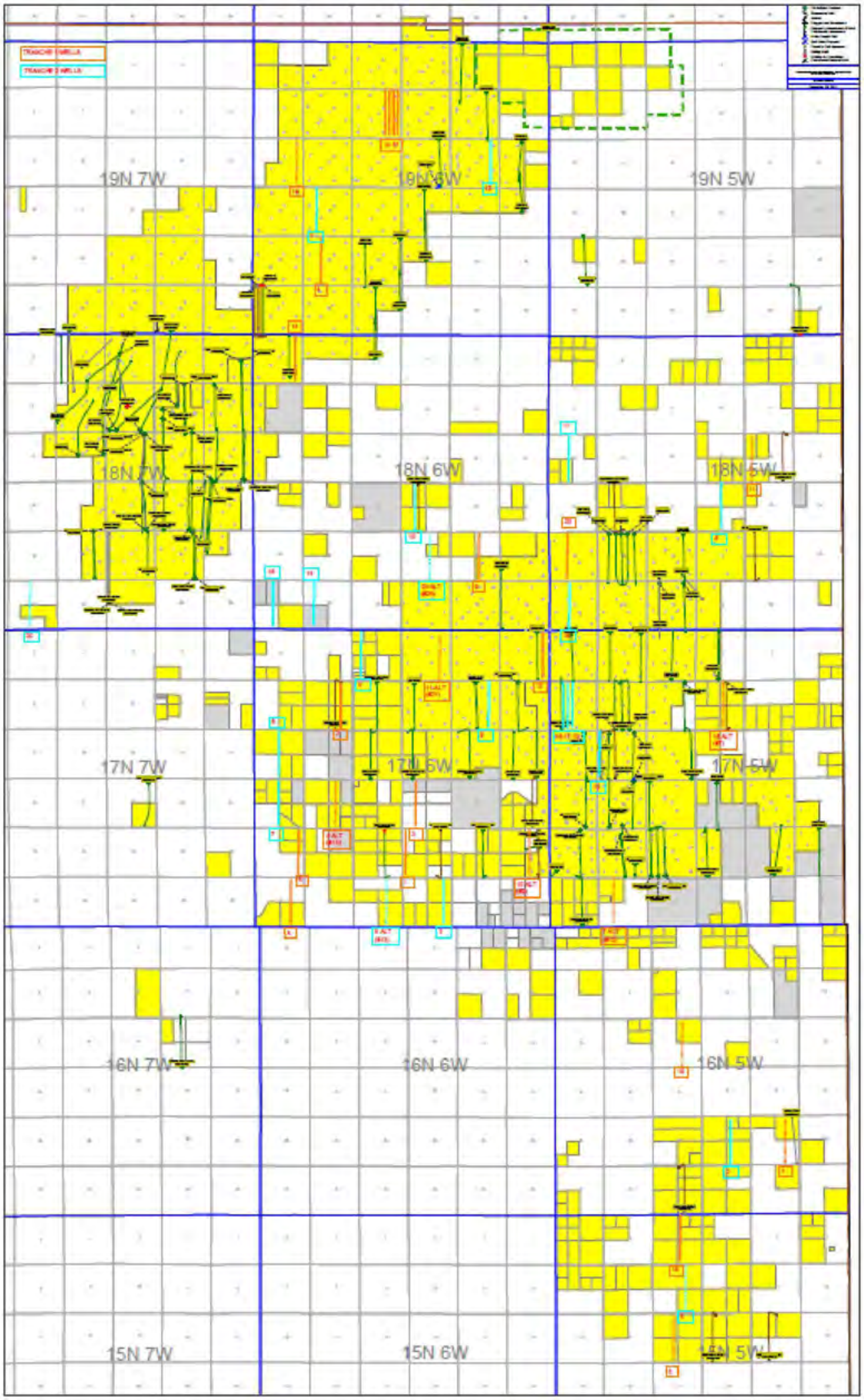
Well Schedule

KEY
Tranche 1
Tranche 2
Substitute Wells
Excluded Wells

Asset Name	Target	Lat Length	Orientation	Lateral Spacing (FT)	Vertical Spacing (FT)	LocationID	Prop_ID	Spud Date (Start)	TD (End)	Rig Name	Frac Start
EHU 230	MLL	5100	S to N	660	180	19N06W31D_MISS	OB8GQ47E9A	11/16/15	12/3/15	Latshaw Drill Rig 12	2/7/16
Paris 1706 5---28MH	MLL	4900	N to S	660	180	17N06W28E_MISS	Q4LG1GI14Z	11/23/15	12/15/15	Latshaw Drill Rig 39	12/30/15
EHU 231	MLM-	5100	S to N	660	180	19N06W31C_MISS	OB8GR1Q2BA	12/4/15	12/22/15	Latshaw Drill Rig 12	2/12/16
Helen 1605 5---33MH	MLL	4900	N to S	660	180	16N05W33D_MISS	Q4LFTPBJFJ	12/16/15	1/3/16	Latshaw Drill Rig 39	1/18/16
EHU 232	MLL	5100	S to N	660	180	19N06W31B_MISS	OB8GO8H9AA	12/23/15	1/7/16	Latshaw Drill Rig 12	2/17/16
Foster 1706 5---24MH	MLL	4900	S to N	660	180	17N06W24E_MISS	OB8GPBH2MA	1/4/16	1/19/16	Latshaw Drill Rig 39	2/3/16
EHU 233	MLM-	5100	S to N	660	180	19N06W31A_MISS	OB8GR1U3CA	1/8/16	1/23/16	Latshaw Drill Rig 12	2/22/16
Francis 1706 5---8MH	MLL	4900	N to S	660	180	17N06W08E_MISS	Q4LG21I08Z	1/11/16	2/2/16	Latshaw Drill Rig 29	2/27/16
Wakeman 1706 6---25MH	MLL	4900	S to N	660	180	17N06W25F_MISS	OB8GQFN87A	1/20/16	2/4/16	Latshaw Drill Rig 39	3/2/16
Brown 1706 6---27MH	MLL	4900	S to N	660	180	17N06W27F_MISS	Q4LG1F653Z	1/24/16	2/8/16	Latshaw Drill Rig 12	3/7/16
Crosswhite 1805 3---20MH	MLL	4900	S to N	660	180	18N05W20C_MISS	Q4LGKCL65X	2/3/16	2/18/16	Latshaw Drill Rig 29	3/12/16
Gilbert 6---21MH	MLL	4900	N to S	660	180	17N06W21F_MISS	Q4LG1B625Z	2/5/16	2/20/16	Latshaw Drill Rig 39	3/17/16
EHU 234	MLL	5100	S to N	660	180	19N06W20D_MISS	OB8GQ3C9YA	2/9/16	2/24/16	Latshaw Drill Rig 12	3/26/16
Cleveland 1805 2---26MH	MLL	4900	S to N	660	180	18N05W26B_MISS	Q4LGKJQ8MK	2/19/16	3/5/16	Latshaw Drill Rig 29	3/22/16
Clark 1705 7---12MH	MLL	4900	N to S	660	180	17N05W12G_MISS	Q4LG0LFCFJ	2/21/16	3/7/16	Latshaw Drill Rig 39	No Data
EHU 235	MLL	5100	N to S	660	180	19N06W29D_MISS	OB8GQ4R86A	2/25/16	3/11/16	Latshaw Drill Rig 12	3/31/16
Matheson 1705 5---10MH	MLL	4900	S to N	660	180	17N05W10E_MISS	Q4LG0IC23J	3/6/16	3/21/16	Latshaw Drill Rig 29	4/10/16
Rigdon 1705 6---11MH	MLL	4900	S to N	660	180	17N05W11F_MISS	Q4LG0JU15J	3/8/16	3/23/16	Latshaw Drill Rig 39	4/15/16
Ray 1605---27MH	MLL	4900		660	180	16N05W27G_MISS	Q4LFTI6OXJ	3/12/16	3/27/16	Latshaw Drill Rig 12	4/19/16
Dixon 1505---16MH	MLL	4900		660	180	15N05W16A_MISS	Q4LGJ3CCIX	3/22/16	4/6/16	Latshaw Drill Rig 29	4/29/16
Gregory	MLL	4900		660	180	17N05W01D_MISS	Q4LG0G46YJ	3/24/16	4/8/16	Latshaw Drill Rig 39	5/4/16
Cronkite	MLL	4900		660	180	15N05W14D_MISS	Q4LGJ0QAAX	3/28/16	4/12/16	Latshaw Drill Rig 12	5/9/16
Lankard	MLL	4900		660	180	17N06W34F_MISS	Q4LG1O0ESZ	4/7/16	4/22/16	Latshaw Drill Rig 29	5/18/16
Smith	MLL	4900		660	180	17N06W30G_MISS	Q4LG1JR6DZ	4/9/16	4/24/16	Latshaw Drill Rig 39	5/23/16
Airheart	MLL	4900		660	180	15N05W04A_MISS	Q4LGJ7NARX	4/13/16	4/28/16	Latshaw Drill Rig 12	5/28/16
Shutler	MLL	4900		660	180	17N05W32F_MISS	Q4LG106C3Z	4/23/16	5/8/16	Latshaw Drill Rig 29	6/6/16
Todd	MLL	4900		660	180	17N06W04A_MISS	Q4LG1O2CRZ	4/25/16	5/10/16	Latshaw Drill Rig 39	6/11/16
Veith	MLL	4900		660	180	16N05W26E_MISS	Q4LFTGLTUJ	4/29/16	5/14/16	Latshaw Drill Rig 12	6/16/16
Lacy	MLL	4900		660	180	17N06W33G_MISS	Q4LG1M96JZ	5/9/16	5/24/16	Latshaw Drill Rig 29	6/30/16
Harrison	MLL	4900		660	180	17N06W20A_MISS	Q4LG18CEOZ	5/11/16	5/26/16	Latshaw Drill Rig 39	7/5/16
Martin	MLL	4900		660	180	15N05W09A_MISS	Q4LGJEBEAX	5/15/16	5/30/16	Latshaw Drill Rig 12	7/10/16
Trindle	MLL	4900		660	180	17N06W31E_MISS	Q4LG1KO9HZ	5/25/16	6/9/16	Latshaw Drill Rig 29	7/24/16
Themer 1706 6---6MH	MLL	4900		660	180	17N06W06F_MISS	Q4LG1S91WZ	5/27/16	6/11/16	Latshaw Drill Rig 39	7/29/16
Rudd	MLL	4900		660	180	16N05W05D_MISS	Q4LG02MC3J	5/31/16	6/15/16	Latshaw Drill Rig 12	8/3/16
Edwin	MLL	4900		660	180	18N05W22D_MISS	Q4LGKF528X	6/10/16	6/25/16	Latshaw Drill Rig 29	8/17/16
Wendt	MLL	4900		660	180	18N06W26E_MISS	Q6IK997085	6/12/16	6/27/16	Latshaw Drill Rig 39	8/22/16
Hasley	MLL	4900		660	180	16N05W28E_MISS	Q4LFTJ6P1J	6/16/16	7/1/16	Latshaw Drill Rig 12	8/27/16
Pollard	MLL	4900		660	180	18N05W02D_MISS	Q4LGKBR21X	6/26/16	7/11/16	Latshaw Drill Rig 29	9/10/16
Boecher	MLL	4900		660	180	17N06W19D_MISS	Q4LG1844MZ	6/28/16	7/13/16	Latshaw Drill Rig 39	9/15/16
GST16N05W16A_MISS	MLL	4900		660	180	16N05W16A_MISS	Q4LFT9TMD3	7/2/16	7/17/16	Latshaw Drill Rig 12	9/20/16
Vadder	MLL	4900		660	180	18N05W12A_MISS	Q4LGK23AGK	7/12/16	7/27/16	Latshaw Drill Rig 29	10/4/16
Evelyn	MLL	4900		660	180	17N06W18D_MISS	Q4LG16S1GJ	7/14/16	7/29/16	Latshaw Drill Rig 39	10/9/16
Holiday	MLL	4900		660	180	17N07W25A_MISS	Q85KR0X1TQ	7/18/16	8/2/16	Latshaw Drill Rig 12	10/14/16
Oltmanns	MLL	4900		660	180	18N05W14A_MISS	Q4LGK3O5HX	7/28/16	8/12/16	Latshaw Drill Rig 29	10/28/16
Miller	MLL	4900		660	180	17N06W03D_MISS	OB8GR7H0GI	7/30/16	8/14/16	Latshaw Drill Rig 39	11/2/16
Musick 1706 5---11H	MLL	4900	S to N	660	180	17N06W11F_MISS	OB8GP5L4KA	8/3/16	8/18/16	Latshaw Drill Rig 12	11/7/16
Carey	MLL	4900		660	180	18N05W06D_MISS	Q4LGK5R16K	8/13/16	8/28/16	Latshaw Drill Rig 29	11/21/16
Greene	MLL	4900		660	180	17N06W01G_MISS	OB8GRET5RA	8/15/16	8/30/16	Latshaw Drill Rig 39	11/26/16
Weber	MLL	4900		660	180	18N06W22A_MISS	Q85KRDHBT6	8/29/16	9/13/16	Latshaw Drill Rig 29	12/15/16
Elling 1505 2---15MH	MLL	4900		660	180	15N05W15B_MISS	Q4LGJ220AH	8/31/16	9/15/16	Latshaw Drill Rig 39	12/20/16
EHU18N06W06F_MISS	MLL	4900		660	180	18N06W06F_MISS	OB8GRKS3OA	9/4/16	9/19/16	Latshaw Drill Rig 12	12/25/16
Nelson	MLL	4900		660	180	18N05W18D_MISS	Q4LGK8R1SX	9/14/16	9/29/16	Latshaw Drill Rig 29	1/1/17
EHU 236	MLL	4900		660	180	19N06W09D_MISS	OB8GQDK9DA	9/16/16	10/1/16	Latshaw Drill Rig 39	1/20/17
EHU19N06W19C_MISS	MLL	4900		660	180	19N06W19C_MISS	OB8GQR9BKA	9/20/16	10/5/16	Latshaw Drill Rig 12	1/4/17
Mitchell	MLL	4900		660	180	18N06W27A_MISS	Q4LGLIH2N0	9/30/16	10/15/16	Latshaw Drill Rig 29	1/8/17
EHU 237	MLL	4900		660	180	19N06W09E_MISS	OB8GQMECMA	10/2/16	10/17/16	Latshaw Drill Rig 39	1/25/17
EHU19N06W14G_MISS	MLL	4900		660	180	19N06W14G_MISS	OB8GQO9BZA	10/6/16	10/21/16	Latshaw Drill Rig 12	1/10/17
Steele	MLL	4900		660	180	18N06W34C_MISS	OB8GRD35MA	10/16/16	10/31/16	Latshaw Drill Rig 29	1/15/17
EHU 238	MLL	4900		660	180	19N06W09F_MISS	OB8GOAK8OA	10/18/16	11/2/16	Latshaw Drill Rig 39	1/29/17
Horn 1705 4---17MH	MLL	4900		660	180	17N05W17A_MISS	OB8GQHGCOI	10/22/16	11/6/16	Latshaw Drill Rig 12	No Data
McNulty	MLL	4900		660	180	18N06W33A_MISS	Q85KRQ51F6	11/1/16	11/16/16	Latshaw Drill Rig 29	1/20/17
EHU 239	MLL	4900		660	180	19N06W09G_MISS	OB8GQM9BLA	11/3/16	11/18/16	Latshaw Drill Rig 39	2/3/17
GST15N05W03F_MISS	MLL	4900		660	180	15N05W03F_MISS	Q4LGI6W2LH	11/7/16	11/22/16	Latshaw Drill Rig 12	1/23/17
TMP18N06W32C_MISS	MLL	4900		660	180	18N06W32C_MISS	Q85KRNBD26	11/17/16	12/2/16	Latshaw Drill Rig 29	1/29/17
EHU19N06W18G_MISS	MLL	4900		660	180	19N06W18G_MISS	OB8GQ2WASA	11/19/16	12/4/16	Latshaw Drill Rig 39	2/8/17
GST15N05W04B_MISS	MLL	4900		660	180	15N05W04B_MISS	Q4LGJ7R1NH	11/23/16	12/8/16	Latshaw Drill Rig 12	2/1/17
TMP18N06W31E_MISS	MLL	4900		660	180	18N06W31E_MISS	Q85KRKW0A6	12/3/16	12/18/16	Latshaw Drill Rig 29	2/8/17
EHU19N06W07G_MISS	MLL	4900		660	180	19N06W07G_MISS	OB8GQLEAFA	12/5/16	12/20/16	Latshaw Drill Rig 39	2/11/17
GST15N05W04D_MISS	MLL	4900		660	180	15N05W04D_MISS	Q4LGJ83EVX	12/9/16	12/24/16	Latshaw Drill Rig 12	2/13/17
Burpo 1705 3---7MH	MLM	4900	N to S	660	180	17N05W07C_MISS	OB8GQH29LI	12/19/16	1/3/17	Latshaw Drill Rig 29	3/2/17
LNU18N05W30D_MISS	MLL	4900		660	180	18N05W30D_MISS	OB8GP8M33A	12/21/16	1/5/17	Latshaw Drill Rig 39	2/22/17
GST15N05W04F_MISS	MLL	4900		660	180	15N05W04F_MISS	Q4LGJ8D0PH	12/25/16	1/9/17	Latshaw Drill Rig 12	2/18/17
Burpo 1705 4---7MH	MLL	4900	N to S	660	180	17N05W07D_MISS	Q4LEKJ1GY6	1/4/17	1/19/17	Latshaw Drill Rig 29	3/4/17
LNU18N05W31D_MISS	MLL	4900		660	180	18N05W31D_MISS	OB8GQB1EKA	1/6/17	1/21/17	Latshaw Drill Rig 39	2/27/17
GST15N05W05A_MISS	MLL	4900		660	180		Q4LGJ8LBUX	1/10/17	1/25/17	Latshaw Drill Rig 12	2/22/17
Burpo 1705 5---7MH	MLM	4900	N to S	660	180	17N05W07E_MISS	OB8GR2J3KA	1/20/17	2/4/17	Latshaw Drill Rig 29	3/4/17
TMP18N07W32D_MISS	MLL	4900		660	180	18N07W32D_MISS	Q85KS27296	1/22/17	2/6/17	Latshaw Drill Rig 39	3/7/17
GST15N05W05C_MISS	MLL	4900		660	180		Q4LGJ9CAWX	1/26/17	2/10/17	Latshaw Drill Rig 12	3/9/17

Locations Map (still subject to final adjustments)



Example Early Well AFE

Part 1

OPERATOR: ALTA MESA SERVICES, LP	PROSPECT / WELL NAME: FRANCIS 1706 5-8MH		AFE NUMBER: TBD
FIELD NAME: NEKINGFISHER	COUNTY: KINGFISHER	STATE: OKLAHOMA	REVISION: 2.0
TARGET FORMATION: MISS LIME - DEEP			REVISION DATE: 15-Oct-15
LOCATION: SL: 208' FNL & 1259' FEL - NE/4 - SEC08 17N 6W; BHL: 200' FSL & 1898' FEL - SE/4 - SEC08 17N 6W	TP: 200' FNL & 1888' FEL - NE/4 - SEC08 17N 6W		PROPOSED DEPTH: 12602 ft MD / 7577 ft TVD

	INTANGIBLE WELL COSTS	DRILLING 8200	COMPLETION 8300	COMPLETED TOTAL
050	WELLSITE SUPERVISION	$ 26,752.00	$ 13,600.00	$ 40,352.00
100	PERMITTING / REGULATORY	$ 500.00	$ -	$ 500.00
101	SURVEYS & STUDIES	$ 1,350.00	$ -	$ 1,350.00
102	RIGHT OF WAY, DAMAGES, & LEGAL	$ 11,666.67	$ -	$ 11,666.67
103	PHYSICAL LOCATION PREPARATION	$ 58,865.00	$ -	$ 58,865.00
104	LOCATION CLEAN-UP & RESTORATION	$ 2,500.00	$ -	$ 2,500.00
105	GATE GUARD	$ -	$ -	$ -
107	LEGAL / UNITIZATION	$ -	$ -	$ -
110	MOBILIZATION / DEMOBILIZATION (Move In - Move Out)	$ 30,333.33	$ -	$ 30,333.33
120	RIG TURNKEY COSTS	$ -	$ -	$ -
121	RIG FOOTAGE COSTS	$ -	$ -	$ -
122	RIG DAY WORK COSTS	$ 250,800.00	$ 7,500.00	$ 258,300.00
123	COMPLETION / WORKOVER RIG	$ -	$ 20,000.00	$ 20,000.00
124	COILED TUBING UNIT	$ -	$ 25,000.00	$ 25,000.00
125	WIRELINE UNIT	$ -	$ -	$ -
126	SLICKLINE - BRAIDED LINE	$ -	$ -	$ -
128	PUMP TRUCK/PUMP SERVICES	$ -	$ 10,000.00	$ 10,000.00
130	FUEL & LUBRICANTS	$ 41,216.00	$ 4,725.00	$ 45,941.00
131	WATER	$ 1,900.00	$ 62,850.00	$ 64,750.00
140	BITS	$ 33,000.00	$ 3,500.00	$ 36,500.00
141	REAMERS, STABILIZERS, COLLARS	$ 4,422.00	$ 50.00	$ 4,472.00
142	ROTARY TOOL RENTAL & ACCESSORIES	$ 25,725.00	$ 8,237.50	$ 33,962.50
144	FISHING TOOLS	$ -	$ -	$ -
145	DIRECTIONAL TOOLS	$ 121,090.00	$ -	$ 121,090.00
149	BOP TESTING AND REPAIRS	$ -	$ 2,500.00	$ 2,500.00
150	WELL CONTROL EQUIP RENTAL	$ 4,527.60	$ 3,135.00	$ 7,662.60
151	MUD MONITORING & EQUIPMENT RENTAL	$ 28,873.00	$ 1,075.00	$ 29,948.00
152	MUD LOGGING & SAMPLING	$ 11,616.00	$ -	$ 11,616.00
153	SURFACE EQUIPMENT RENTAL	$ 19,085.10	$ 60,360.00	$ 79,445.10
154	DOWNHOLE EQUIPMENT RENTAL	$ -	$ -	$ -
160	MUD & CHEMICALS	$ 91,654.00	$ 13,600.00	$ 105,254.00
161	CUTTING DISPOSAL / BARGE CLEAN-UP	$ 26,440.00	$ 1,000.00	$ 27,440.00
170	TUBULAR INSPECTION & TESTING	$ 8,500.00	$ -	$ 8,500.00
171	CASING CREWS	$ 19,500.00	$ 15,000.00	$ 34,500.00
172	CEMENTING & SERVICES	$ 32,500.00	$ -	$ 32,500.00
173	LOGGING & CORING	$ -	$ -	$ -
174	PERFORATING	$ -	$ 102,500.00	$ 102,500.00
175	ACID, FRAC, & SAND CONTROL	$ -	$ 890,000.00	$ 890,000.00
176	WELL TESTING	$ -	$ 36,000.00	$ 36,000.00
177	NITROGEN/CO2	$ -	$ -	$ -
178	COMMUNICATIONS	$ 6,741.48	$ 1,192.00	$ 7,933.48
179	OTHER SERVICES	$ 16,950.00	$ 117,250.00	$ 134,200.00
180	LAND TRANSPORTATION	$ 16,720.00	$ 3,500.00	$ 20,220.00
181	MARINE TRANSPORTATION	$ -	$ -	$ -
182	AIR TRANSPORTATION	$ -	$ -	$ -
189	WELLHEAD SERVICES	$ 1,500.00	$ 3,000.00	$ 4,500.00
190	CONTRACT LABOR	$ -	$ -	$ -
191	COMPANY LABOR	$ -	$ -	$ -
192	SUPERVISION - GEOLOGICAL & ENGINEERING	$ -	$ 9,000.00	$ 9,000.00
193	TRAILER & CAMP EXPENSES	$ 26,392.00	$ 11,700.00	$ 38,092.00
194	DOCK CHARGES	$ -	$ -	$ -
200	DRILLING OVERHEAD (COPAS)	$ -	$ -	$ -
210	INSURANCE	$ 18,558.00	$ 4,876.00	$ 23,434.00
220	INSURANCE CLAIMS	$ -	$ -	$ -
260	VAC TRUCK SERVICES	$ -	$ -	$ -
261	SALT WATER DISPOSAL		$ -	$ -
290	CONTINGENCIES	$ 93,967.72	$ 143,115.05	$ 237,082.77
291	DRY-HOLE P&A CONTINGENCY	$ -	$ -	$ -
450	LEASE CREW & RENTALS	$ -	$ -	$ -
500	H2S SAFETY SERVICE	$ -	$ -	$ -
600	SWABBING		$ -	$ -
604	DOWNHOLE EQUIPMENT INSPECTION/REPAIR	$ -	$ -	$ -
	(1) TOTAL INTANGIBLE	$ 1,033,645	$ 1,574,266	$ 2,607,910

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Example Early Well AFE

Part 2

	TANGIBLE WELL COSTS	DRILLING 8250	COMPLETION 8350	COMPLETED TOTAL
101	PLATFORM / WELL PROTECTOR - (Wood pilings, metal supports, etc...)	$ -		$ -
150	DRIVE PIPE	$ -		$ -
170	CONDUCTOR PIPE	$ 2,000.00		$ 2,000.00
200	SURFACE CASING	$ 9,430.00		$ 9,430.00
250	INTERMEDIATE CASING	$ 142,931.00		$ 142,931.00
270	LINER	$ -		$ -
300	CASINGHEAD - (Everything up to the tubinghead)	$ 13,900.00		$ 13,900.00
350	CASING EQUIPMENT - (Float equipment, centralizers, liner hangers, etc...)	$ 5,100.00		$ 5,100.00
400	DOWNHOLE EQUIPMENT - (Packers, Anchors, Bridge Plugs, Screens, etc...)	$ -		$ -
900	TANGIBLE CONTINGENCIES	$ 17,336.10		$ 17,336.10
100	PRODUCTION CASING		$ -	$ -
110	PRODUCTION LINER		$ 47,747.00	$ 47,747.00
117	LINER, TIE-BACK ASSEMBLIES - (Casing cost, Seal Assem, etc...)		$ 15,000.00	$ 15,000.00
120	TUBING		$ 41,668.00	$ 41,668.00
166	SAFETY SHUTDOWN		$ -	$ -
195	ARTIFICIAL LIFT EQUIPMENT		$ 45,000.00	$ 45,000.00
200	WELLHEAD - (Tubinghead, Hangers, Production Tree, etc...)		$ 16,300.00	$ 16,300.00
300	COMPLETION EQUIPMENT		$ -	$ -
350	CASING EQUIPMENT - (Float equipment, centralizers, liner hangers, etc...)		$ -	$ -
400	DOWNHOLE EQUIPMENT - (Packers, Anchors, Bridge Plugs, Screens, etc...)		$ 105,500.00	$ 105,500.00
700	TANGIBLE CONTINGENCIES		$ 27,121.50	$ 27,121.50
	(2) TOTAL TANGIBLES	$ 190,697.10	$ 298,336.50	$ 489,033.60
	TOTAL D&C WELL COST	$ 1,224,342	$ 1,872,602	$ 3,096,944

	FACILITIES COSTS	FACILITIES 8400		PIPELINE COSTS	PIPELINE 8450
010	FOUNDATION	$ -	100	PIPELINE SURVEYS	$ -
020	PLATFORM	$ -	101	RIGHTS OF WAY	$ -
030	PRODUCTION BARGE	$ -	102	PERMITTING & REGULATORY	$ -
100	TANK BATTERY	$ 75,000.00	103	DAMAGES	$ -
102	PERMITTING/REGULATORY	$ -	104	MATS	$ -
105	ROADS	$ -	108	SURVEYORS	$ -
107	FENCES	$ 500.00	110	LINE PIPE	$ -
110	HEATER TREATER	$ -	111	COATING	$ -
111	COATINGS	$ -	120	VALVES & FITTINGS	$ -
112	LINE HEATER	$ -	122	SEPARATORS	$ -
120	MANIFOLD & SEPARATORS	$ -	124	FILTERS	$ -
122	SEPARATORS	$ -	125	PIG LAUNCHERS/RECEIVERS	$ -
124	FILTERS	$ -	130	METERING & PIPELINE TAP	$ -
130	DEHYDRATOR	$ -	140	INSTALLATION COSTS	$ -
131	PIPING	$ -	142	ROW CLEARING	$ -
140	GENERATOR & ELECTRICITY SYSTEM	$ 10,000.00	146	BORING	$ -
150	METER RUN	$ 3,000.00	162	ENVIRONMENTAL	$ -
160	EMISSION CONTROLS	$ -	175	CATHODIC PROTECTION	$ -
165	INSTRUMENTATION	$ 300.00	180	MANIFOLDS	$ -
166	SAFETY SHUTDOWN	$ -	190	OTHER PIPELINE COSTS	$ -
170	FLOWLINES	$ -	200	COMPANY LABOR & EXPENSE	$ -
175	CATHODIC PROTECTION	$ -	210	CONTRACT SUPERVISION	$ -
177	HYDROCARBON DEWPOINT CONTROL	$ -	215	INSPECTORS	$ -
178	VAPOR RECOVERY	$ -	250	INSURANCE	$ -
179	FLARE	$ -	280	MAJOR CONSTRUCTION OVERHEAD	$ -
180	VALVES & FITTINGS	$ 10,000.00	290	BUDGET CONTINGENCIES	$ -
190	COMPRESSOR	$ -	450	WELDING / X-RAY	$ -
191	PUMP UNITS	$ 4,000.00			
192	SALT WATER DISPOSAL PUMP	$ -			
193	SUCKER RODS	$ -			
194	OTHER ARTIFICIAL LIFT EQUIPMENT	$ -			
195	INSTALLATION LABOR	$ 9,500.00			
196	OTHER FACILITIES COST	$ -			
200	COMPANY LABOR & EXPENSE	$ -			
210	CONTRACT SUPERVISION	$ -			
220	INSURANCE CLAIMS	$ -			
280	MAJOR CONSTRUCTION OVERHEAD	$ -			
290	BUDGET CONTINGENCIES	$ 11,230.00			
	(3) TOTAL FACILITIES COST	$123,530		(4) TOTAL PIPELINE COST	$0

DRILLING INTANGIBLE COST	$1,033,645	COMPLETED INTANGIBLE	$2,607,910	TOTAL FACILITIES COST	$123,530
DRILLINGTANGIBLE COST	$190,697	COMPLETED TANGIBLE	$489,034	TOTAL PIPELINE COST	$0
DRILLING TOTAL COST	$1,224,342	COMPLETED TOTAL	$3,096,944	TOTAL PROJECT COST	$3,220,474

PREPARED BY: ALEXIS HUSSER		APPOVAL:	DATE
APPROVAL:		APPROVAL:	DATE

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IV. Transaction Review

Drilling Partnerships

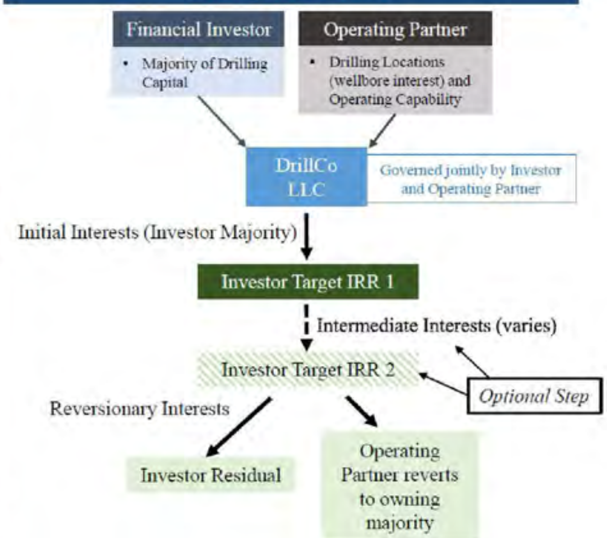
The Structure

The Basics

Overview

- **Flexible Financing Alternative for E&P Companies**
  - Financial investor provides drilling capital to operator in exchange for wellbore ownership through an off-balance sheet arrangement
  - Financial investor receives return of capital plus an IRR (usually between 10–15%), thereafter a specified portion of the financial investor's initial interest reverts to the operator
    - IRR can be measured on a well-by-well basis (operator favorable) or across a portfolio of wells (financial investor favorable)
    - Sometimes there is an extra step added, with a second target IRR to be achieved by investor
  - Financial investor retains upside in the structure via an ultimate reversionary interest in the wells
  - **<u>Financial investor is able to earn its way into a development program without exposing itself to the operator's balance sheet or broader asset base</u>**
    - Surgical investment through which financial investor can gain access to only the wellbores and assets it desires
    - Program is scalable to include additional locations and asset packages

Example Structure



BCE's Approach to Drilling Partnerships

Subject Acreage Checks all of the Boxes

Drilling Partnership Asset Criteria and Risk Profile: Ensuring a Repeatable, Low Risk Return

Asset Criteria	Relevance to Structure	BCE Partner's STACK Asset
1. Operated asset base in fields that have vertical and horizontal development history and records	1. Ensures BCE can control timing of development and asset is geologically de-risked	1. Acreage has hundreds of vertical and horizontal wells; Partner has operated acreage for 20+ years
2. Operator history of drilling wells within the field and highly refined / repeatable "type-well"	2. Removes geologic, mechanical and reservoir risk; BCE funds go towards development, not "R&D"	2. Partner has drilled more than 60 horizontal wells across its position over the preceding 3 years
3. Single well economics in excess of 30% IRR at current NYMEX strip	3. BCE solely targets best-in-class assets with robust returns	3. Type well produces a ~55% IRR at the 11.23.15 NYMEX Futures Strip
4. CAPEX and lease operating expense optimization opportunities from program drilling and improved efficiencies	4. BCE returns increased via leveraging efficiencies of programmatic drilling and enhanced scale of operator	4. Multiple horizontal wells per section reduces per well cost; enhanced gas processing plant to come online in field in 1H 2015 – boost to revenue
5. Opportunity to expand program within initial field	5. Wells "cheap" to add and enhance MOIC via cash recycling	5. ~70,000 net acre position could support ~2,500 horizontal drilling locations; BCE has 4 year exclusivity
6. Reliable and redundant infrastructure in place; treating, gathering, electrical lines, water handling and disposal	6. Eliminates delays putting wells to sales and ensures BCE capital is not being directed to non-revenue generating purposes	6. Region has supported major oil and gas operations for several decades and is now a renewed focus for the industry
7. Stable regulatory environment and service company availability	7. Minimal delays; operations are focus, not paperwork	7. Partnership rigs are under contract and wells are currently being permitted

BCE's structure was fine-tuned, within the context of ongoing and competitive negotiations with AMH, in order to provide strong risk-adjusted returns even in the case of sustained low commodity prices. Once it became apparent that AMH management was fixated on a two hurdle structure (with initial and final payout IRRs), BCE realized an opportunity to make an ostensive "give" on terms to the Company that would actually enhance BCE's returns. This was accomplished by negotiating a larger intermediate period interest of 20% (the period between initial and final payout) in return for offering AMH a larger upfront carry of 20%. Perhaps counterintuitively, the larger upfront carry is also independently to the benefit of BCE's economics in terms of aggregate proceeds, MOIC and ultimately profit by delaying the achievement of initial payout, and further delaying the achievement of final payout, lengthening the period wherein DrillCo has a larger share of cashflows (80% or 20%).

Negotiated Terms Superior to other Announced Drilling Partnerships

BCE Agreed Terms vs. Other Announced Drilling Partnerships

	TPG - LGCY	GSO - LINE	? - MHR	IOG - LNR	BCE - ?
Terms					
Sponsor CapEx Commitment ($MM)	$150	$500	$430	$100	$128
Sponsor CapEx Share	95%	100%	100%	90%	---
Sponsor Initial CF Interest	87.5%	85%	100%	90%	80%
Sponsor CF Interest after 1.0x ROI	63%	85%	100%	90%	80%
IRR Hurdle	15%	15%	12%	15%	15%
Sponsor CF Interest after IRR Hurdle	15%	5%	10%	10%	20%
Secondary IRR Hurdle	-	-	16%	-	25%
Sponsor CF Interest after Secondary Hurdle	-	-	5%	-	7.5%
AMI - Target Area	Permian	Multiple	Utica	Eagle Ford	STACK
Availability Term	Flexible	5 years	Flexible	Flexible	Flexible
Cash-on-Cash (unlevered) Returns on a 40 well program of BCE's Partner's STACK Type Well at 11.23.15 NYMEX					
IRR	25.7%	18.9%	19.7%	25.3%	24.1%
MOIC	1.8x	1.4x	1.4x	1.7x	**1.9x**
Profit ($MM)	$71.5	$40.2	$35.4	$53.3	**$88.8**

Others' capital exposure not capped – risk of "trainwreck" well costs

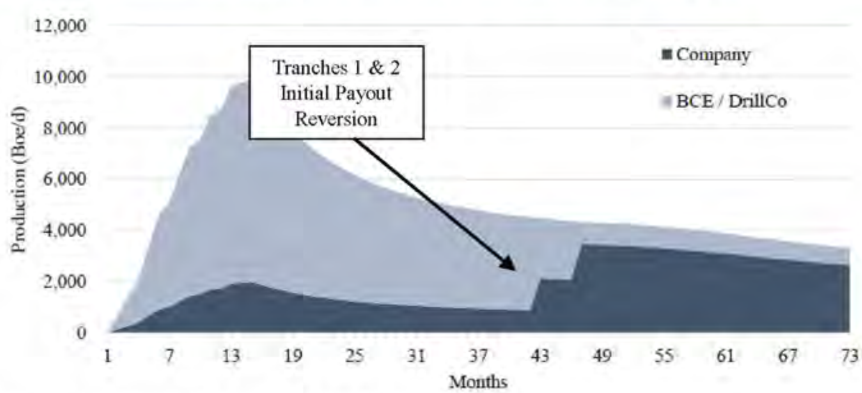
BCE CapEx capped at $3.2MM per well

CapEx cap substantially de-risks BCE returns

BCE's structure provides a superior risk-adjusted, unlevered ROI to other announced Drilling Partnerships; BCE's structure was uniquely tailored to optimize profits based on the Partner's demonstrated well type curves

Note: No sale of residual interest assumed for this comparison of terms

Illustrative Production Sharing between Company and DrillCo



<u>DrillCo & the Joint Development Agreement ("JDA")</u>

BCE has formed a special purpose entity, BCE-STACK Development LLC ("DrillCo"), to fulfill the contemplated financial obligations outlined in the JDA. Contemporaneous with the Closing of the DrillCo, AMH and BCE will agree on the initial two Development Plans. Each Development Plan will contain 20 proposed wells along with

an additional number of substitute wells that AMH may elect to replace for one of the previously identified wells. AMH may amend an approved Development Plan from time to time, only with the consent of BCE, based on current conditions and drilling results obtained. BCE and AMH will create an Operating Committee which will hold planning sessions and performance reviews. The Operating Committee will include an equal number of representatives from BCE and AMH and will meet at least quarterly to share technical data, discuss historical and forecasted drilling and completion and performance results, and discuss future potential development operations and Development Plans.

The Operating Committee will permit certain discretionary adjustments to the agreed to Development Plan, including, changing the order in which wells are drilled, and modifications to the costs agreed to in the AFE that reflect then-current market conditions and verifiable changes in service costs (provided they are changes consistent with service costs charged on all STACK wells drilled by AMH) up to a maximum $150,000. AMH has maintained their cost structure over the prior 12 months while doubling the amount of completion stages and consequently IP rates and EURs. If service cost inflation occurred and/or AMH was able to demonstrate that a more costly completion technique resulted in superior well results versus the existing Development Plan AFEs, BCE felt it prudent to allow for higher well costs to ensure DrillCo could maximize returns and not impede the development of the 40 wells.

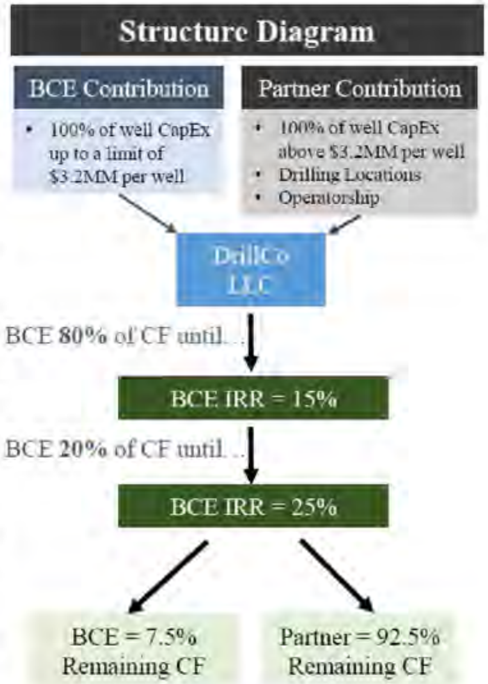
Each proposed Development Plan will include: (i) the number of wells expected to be drilled, including, for each well, the anticipated target formation, lateral length, orientation, surface location, completion plans, well drainage and spacing plans (including with respect to wells contemplated to be drilled concurrently by AMH within and adjacent to DrillCo's wells) and unit designation; (ii) projected spud, completion, and first production dates; (iii) AFEs for each applicable well, which shall reflect the working interest and net revenue interest for each well, and the estimated drilling, completion and equipping costs for each well, and the number of completion stages; and (iv) the estimated costs associated with renewal, extension and curative matters with respect to the leases covering wells included within such Development Plans.

Once the Development Plan is mutually agreed to, AMH will begin delivering AFEs for the execution of the Development Plan. Concurrent with the execution of the JDA, AMH will provide AFEs for the initial 4 development wells, which DrillCo is obligated to fund within 12 business days. All subsequent AFEs will require DrillCo funding within 30 days of receipt. Upon funding of the AFE, BCE will earn 80% of AMH's right, title and interest in and to the wellbore (the "Pre-Reversionary Interest"). Subject to the $3.2 million maximum capital commitment per well, BCE is then obligated to fund 100% of the AFE costs in accordance with the Development Plan. Once DrillCo has achieved a 15% IRR for all 20 wells drilled in the Development Plan ("Initial Payout"), DrillCo's interest in the wells will automatically reduce from 80% to 20% (the "Initial Reversionary Interest"). Once DrillCo has achieved a 25% IRR for all 20 wells drilled in the Development Plan ("Final Payout"), DrillCo's working interest in the wells will automatically reduce from 20% to 7.5% ("Final Reversionary Interest").

AMH will have an option to purchase DrillCo's Final Reversionary Interest in the wells drilled under each Development Plan by paying the Fair Market Value thereof. Fair Market Value will be determined by an advisory firm mutually acceptable to AMH and DrillCo in the event AMH and DrillCo are unable to mutually agree to a value.

Additional pertinent JDA provisions include the following:

- BCE agrees to not form similar financial drilling partnerships within Kingfisher County with other operators without the prior written consent of AMH, and AMH agrees to not enter into discussions or agreements for a similar financial DrillCo within Kingfisher County.
- The JDA affords both parties the ability, if mutually agreed to, to add up to two additional Development Plans (40 additional wells) to DrillCo.
- Term: Assuming no defaults by either party, the JDA and rights thereunder will remain in in force until the earlier to occur of (i) mutual agreement by both parties; (ii) Final Payout of all Development Plans; (iii) four year anniversary of the closing.
- Drag Rights: AMH may drag DrillCo into a sale provided all Development Wells have been drilled and completed, and DrillCo will receive the no less than the greater of 2.0x MOIC and 25% IRR.
- Tag Rights: DrillCo can elect to tag-along in a sale by AMH on identical terms and conditions as agreed to by AMH for DrillCo's proportionate interest in such wells being sold.
- Transfer Restrictions: DrillCo may not transfer its interests in wells until the earlier to occur of (i) two years following the last Development Well being drilled and completed and (ii) Initial Payout of such Development Plan.



Exclusivity Period

DrillCo has a period of exclusivity to negotiate in good faith the JDA and affiliated documents. The exclusivity runs through January 15, 2016. If either AMH or BCE fail to negotiate in good faith there is a $1.0 million penalty payable to the non-defaulting party.

Returns Analysis

Following extensive asset level diligence and 3rd party confirmation from Pinnacle Energy Services' ("PES") reservoir engineers, BCE felt it was unnecessary to arbitrarily apply further risking to AMH's Fall 2015 type curve (the basis for BCE's Base Case modeling). In fact, an average of actual results achieved to date and the composite type curve developed by PES both produce higher returns at the single well level than BCE's base case type curve.

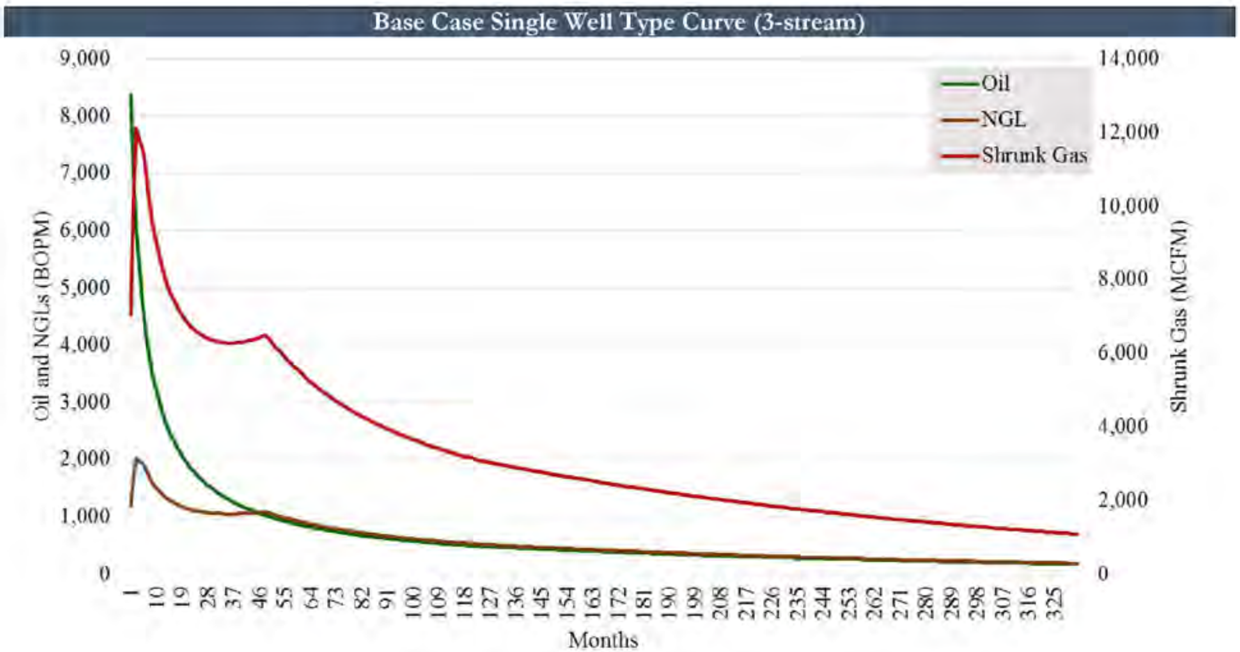
Base Case Assumptions

- AMH Fall 2015 Type Curve used for modeling production (~586 MBoe 30 year EUR: 38% Oil, 31% NGLs, 31% Dry Gas)
  - See graph below
  - 8/8ths (100% working interest) capital cost per well of $3.2 million (BCE's capped exposure)
- 40 joint wells drilled by 2 rigs, one commencing in January 2016, and the other in March 2016
  - 40 wells split into two tranches upon which the economic payout hurdles are measured
  - 19 days to drill a well
  - Wells completed in batches of 2
  - Lag from well spud until first sales of 3 months

- Cashflows received from net proceeds back to DrillCo are "recycled" within DrillCo to fund a portion of subsequent well costs
- DrillCo sells its remaining interests in the Joint Wells after 5 years (January 2021) at a Fair Market Value (PV9 of remaining cashflows)
- LOE
  - $5,623 a month fixed cost per well
  - $2.40 / Bbl variable lifting cost
  - $1.06 / Bbl transport cost
- Severance Tax
  - 2.10% of total revenue for the first 36 months
  - 7.10% thereafter
- COPAS / Overheard (shared by DrillCo and AMH)
  - $700 a month per producing well
  - $7,000 a month per active drilling rig
- 12.24.15 NYMEX Strip pricing used:

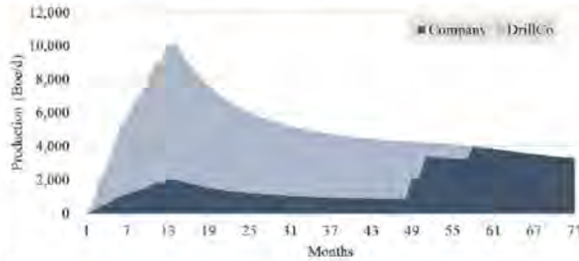
	NYMEX Strip Average Prices						
	2016	2017	2018	2019	2020	2021	2022
Oil	$40.95	$46.17	$49.32	$51.77	$53.39	$54.43	$55.00
Gas	$2.31	$2.73	$2.89	$3.02	$3.17	$3.30	$3.43
NGL	$14.33	$16.16	$17.26	$18.12	$18.69	$19.05	$19.25

  - $0.50 / MCF pricing realization increase from the installation of the new gas plant
    - The Company's assumption is for a $0.75 / MCF pricing uplift



Base Case DrillCo Unlevered Returns and Illustrated Reversion

DrillCo Return ($ in MM)	
DrillCo PV10	$26.8
PV10 as % of Total Project PV10	21%
DrillCo CAPEX	$128.0
DrillCo Max Cash Outflow	$98.2
DrillCo IRR	**24.4%**
DrillCo MOIC	**1.65x**
DrillCo Profit	**$64.0**



Unlevered Base Case BCE LP and Co-Investor Returns (DrillCo Equity)

Within DrillCo Equity Split (Fund | Co-Invest)

Fund MOIC	**1.93x**	Co-Invest MOIC	**1.48x**
Fund IRR	**30%**	Co-Invest IRR	**20%**
Fund Investment	($37.5)	Co-Invest Investment	($60.7)
Fund Profit	**$34.9**	Co-Invest Profit	**$29.1**

BCE LP / Fund Level Base Case Return Sensitivities

IRR

Well Count	Leverage Utilized ($MM): $20	$30	$40	$50	$60
40	**29.5%**	**29.9%**	**30.3%**	**31.5%**	**33.2%**
60	**34.1%**	**34.7%**	**34.9%**	**35.9%**	**36.3%**
80	**37.3%**	**38.2%**	**39.1%**	**39.9%**	**40.4%**
100	**39.6%**	**40.5%**	**41.2%**	**42.3%**	**43.4%**
120	**39.1%**	**41.1%**	**42.7%**	**43.8%**	**45.0%**

MOIC

Well Count	Leverage Utilized ($MM): $20	$30	$40	$50	$60
40	**2.06x**	**2.15x**	**2.26x**	**2.41x**	**2.61x**
60	**2.39x**	**2.45x**	**2.55x**	**2.66x**	**2.78x**
80	**2.74x**	**2.83x**	**2.93x**	**3.05x**	**3.15x**
100	**3.17x**	**3.28x**	**3.36x**	**3.50x**	**3.65x**
120	**3.60x**	**3.63x**	**3.76x**	**3.92x**	**4.10x**

Profit ($MM)

Well Count	Leverage Utilized ($MM): $20	$30	$40	$50	$60
40	**$39.7**	**$43.1**	**$47.4**	**$52.9**	**$60.5**
60	**$52.1**	**$54.4**	**$58.1**	**$62.3**	**$66.9**
80	**$65.4**	**$68.8**	**$72.5**	**$76.8**	**$80.8**
100	**$81.5**	**$85.4**	**$88.5**	**$93.7**	**$99.6**
120	**$97.5**	**$98.6**	**$103.4**	**$109.4**	**$116.1**

Exit Scenarios

There are robust and efficient markets readily available for divesting non-operated working interest. This is especially true for working interests which are non-capex bearing and resemble royalty streams. Buyers of this type of interest include non-operated investment funds, upstream MLPs, royalty trusts, and hedge funds looking to acquire a predictable stream of cash flows as a yield product. Additionally, AMH is a natural buyer of the working interests, and the JDA affords them the opportunity to buyout DrillCo upon Final Payout of the Development Plan at fair market value. If fair market value cannot be jointly agreed to by AMH and DrillCo, a mutually acceptable advisory firm will determine the value on behalf of both parties. Historically parties have been willing to pay between PV8 and PV10 for similar assets.

V. Addendums

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Bayou City | Energy Management

PRIVATE AND CONFIDENTIAL

June 4, 2015

Via Email

Harlan H. (Hal) Chappelle
President & Chief Executive Officer
Alta Mesa Holdings, LP

Re: Letter of Intent to Partner in Sooner Trend Meramec Properties

Dear Hal,

Pursuant to our recent discussions, I am pleased to submit this non-binding letter of intent ("LOI") to partner in the drilling of horizontal Meramec wells in Alta Mesa Holdings, LP's ("Alta Mesa", "Company") Sooner Trend acreage in Kingfisher County, Oklahoma. As you know from our discussions, Bayou City Energy Management ("BCEM") has worked diligently over the past several months to assess and understand the geological, operational, and financial aspects of the Sooner Trend assets. BCEM remains impressed with Alta Mesa's ability to define the multi-bench potential of the resource, increase EURs, demonstrate operational efficiencies, and expand its acreage position. In order to accelerate Meramec development, BCEM proposes the formation of a new Drilling Fund, which is further described below. Subject to confirmatory due diligence, the principal terms of this LOI are as follows:

Drill Fund Framework

BCEM proposes partnering with Alta Mesa to jointly form an off balance sheet entity ("DrillCo") for the purpose of drilling Meramec development wells. BCEM is open to negotiating (higher or lower) the number of wells to be drilled; however, consistent with Alta Mesa's Drilling Fund RFP, the terms presented reflect a 30 well Alta Mesa operated program.

- Alta Mesa will contribute to DrillCo and operate 30 mutually agreed to drilling locations.
- BCEM will contribute 100% of the DrillCo drilling and completion dollars up to a maximum of $3,000,000 to the 8/8ths per well (proportionately reduced to DrillCo's net interest).
- BCEM will receive a preference on cash flows generated by DrillCo until a 12% IRR is achieved on BCEM's total invested capital.
- Upon BCEM achieving a 12% IRR, Alta Mesa will be entitled to 70% of the remaining DrillCo cash flows with BCEM being entitled to a 30% interest in the remaining cash flows.
- Upon BCEM achieving a 12% IRR, Alta Mesa will have a Right of First Offer ("ROFO") on the BCEM portion of the cash flow stream, and the ability to purchase BCEM interests in packages of 10 wells according to chronological order based on the date of initial production. The ROFO becomes effective 3 months after the last of the 10 wells begins producing. Cash flows can be acquired at a PV10 valuation as determined by a mutually agreed to third party engineer.

Importantly, BCEM will not take a direct assignment of wellbores or acreage and 100% of PUDs created and acreage converted to HBP status will accrue outside of the DrillCo structure to Alta Mesa's sole benefit.

Due Diligence

Our proposal is contingent upon completion, to our sole satisfaction, of Meramec asset level due diligence review, including: on-site meetings with management; detailed review of historical and projected results; reserves, acreage leases, drilling obligations, a review of sales to, and any contracts/agreements with midstream/offtake providers, a review of taxes (including implementation of a tax structure satisfactory to us for the proposed transaction), other material contracts, litigation, regulatory, environmental and other similar customary matters. Assuming reasonable access to management and due diligence materials, we would expect our diligence to take 2-3 weeks.

Conditions Precedent

The execution of the Definitive Agreements would be subject to, among other things, the following conditions: (i) completion of due diligence to the satisfaction of BCEM in its sole discretion, (ii) approval of the final terms of the Definitive Agreements by the Investment Committee of BCEM, (iii) execution and delivery of the Definitive Agreements in form and substance acceptable to the Company and BCEM in their sole discretion, (iv) receipt of all necessary regulatory and third party consents and approvals, and (v) the release of liens, if any, held by the financial institutions participating in the Alta Mesa revolving credit agreement on the 30 locations contributed to DrillCo.

Exclusivity & Closing

The work BCEM has performed over the last several months with respect to the Meramec assets uniquely positions it to move swiftly to a close and subsequent prosecution of the DrillCo development plan. As such, BCEM is committed to achieving a closing as early as 30 days post-execution of this LOI. In consideration of our efforts and our incurring significant expenses with our due diligence review as discussed above, Alta Mesa agrees to suspend all discussions and other contacts with any other party with respect to any competing proposed or contemplated transactions with the Company, not to solicit, encourage or discuss any alternative proposals from other parties with respect to any such competing proposed or contemplated transactions, and to negotiate exclusively with us with respect to this LOI for 30 days post-execution of the LOI (the "Exclusive Period"). Further, during the Exclusive Period, the Company agrees to notify us promptly upon receipt of any inquiries regarding the proposed acquisition of any substantial portion of the Company or its assets by any other party.

Please feel free to call me at 713.400.8210 if you have any questions or if you require any further information regarding this proposal. Please note that this LOI will expire at close of business on June 10, 2015. I am, and continue to be, impressed by what Alta Mesa has achieved within the Sooner Trend and look forward to aiding in the acceleration of the development of this world class asset.

Sincerely,

William W. McMullen
Founder | Managing Partner
Bayou City Energy Management LLC

Acknowledged by Alta Mesa Holdings, LP Representative:
Alta Mesa Holdings, LP

By: ______________________________

BCE
BAYOU CITY ENERGY

PRIVATE AND CONFIDENTIAL

July 10, 2015

Via Email

Harlan H. (Hal) Chappelle
President & Chief Executive Officer
Alta Mesa Holdings, LP

Re: Letter of Intent to Partner in Sooner Trend Meramec Properties

Dear Hal,

Pursuant to our recent discussions, I am pleased to submit this revised non-binding letter of intent ("Revised LOI") to partner in the drilling of horizontal Meramec wells in Alta Mesa Holdings, LP's ("Alta Mesa", "Company") Sooner Trend acreage in Kingfisher County, Oklahoma. As you know from our discussions, Bayou City Energy Management ("BCEM") has worked diligently over the past several months to assess and understand the geological, operational, and financial aspects of the Sooner Trend assets. BCEM remains impressed with Alta Mesa's ability to define the multi-bench potential of the resource, increase EURs, demonstrate operational efficiencies, and expand its acreage position. In order to accelerate Meramec development, BCEM proposes the formation of a Drilling Fund, which is further described below. Subject to confirmatory due diligence and a mutually agreed upon drilling schedule the principal terms of this Revised LOI are as follows:

Drill Fund Framework

BCEM proposes partnering with Alta Mesa to jointly form an off balance sheet entity ("DrillCo") for the purpose of drilling Meramec development wells. Concurrently with the formation of DrillCo, Alta Mesa and BCEM will enter into an Asset Acquisition Agreement (the "Acquisition Agreement") pursuant to which AMH will transfer to BCEM an undivided interest (as defined by the Option elected below) of Alta Mesa's interest in the Commitment Wells ("Commitment Wells"), subject to the reversions upon the occurrence of certain events described below.

BCEM is open to expanding the number of locations to be drilled, and as such has provided three options ("Options") for AMH's consideration.

	Option #1	Option #2	Option #3
Commitment Well Count	50	100	150
BCEM Capital Contribution (per well)	100% up $3.2 million	100% up $3.3 million	100% up $3.4 million
Alta Mesa Initial Carried Working Interest up to BCEM 1.0x MOIC	2.5%	3.75%	5.0%
Alta Mesa Before Reversionary IRR Hurdle Carried Working Interest	5.0%	7.5%	10.0%
Reversionary IRR Hurdle	15%	15%	15%
Tail WI upon BCEM Achieving Reversionary IRR Hurdle	85% AMH / 15% BCEM	85% AMH / 15% BCEM	85% AMH / 15% BCEM

Pursuant to the details specific to each of the Options in the table above, BCEM proposes the following:

- Alta Mesa will contribute to DrillCo and operate Commitment Wells comprised of mutually agreed to drilling locations.
- BCEM will contribute 100% of the DrillCo drilling and completion dollars up to the maximum 8/8ths Capital Contribution per well (proportionately reduced to DrillCo's net interest), and receive 100% of the interests associated with the Commitment Wells reduced by certain carried and reversionary interests as outlined below.
    - Alta Mesa will receive the Initial Carried Working Interest, proportionately reduced to DrillCo's net interest, until BCEM has achieved a 1.0x MOIC.
    - Upon BCEM achieving a 1.0x MOIC and until BCEM has achieved the Reversionary IRR Hurdle, Alta Mesa will receive the Before Reversionary IRR Hurdle Carried Working Interest, proportionately reduced to DrillCo's net interest.
    - Upon BCEM achieving the Reversionary IRR Hurdle, BCEM's interest in the Commitment Wells will revert to 15% of DrillCo's original working interest while the remainder will revert to Alta Mesa, increasing Alta Mesa's interest to 85% of its original interest. Any remaining undeveloped Commitment Wells will remain available for future development under the agreed terms.
- Upon BCEM achieving the Reversionary IRR Hurdle, Alta Mesa will have a Right of First Offer ("ROFO") on BCEM's working interest to purchase BCEM interests in packages of 10 wells according to chronological order based on the date of initial production. The ROFO becomes effective 3 months after the last of the 10 wells begins producing.

Due Diligence

Our proposal is contingent upon completion, to our sole satisfaction, of Meramec asset level due diligence review, including: on-site meetings with management; detailed review of historical and projected results; reserves, acreage leases, drilling obligations, a review of sales to, and any contracts/agreements with midstream/offtake providers, a review of taxes (including implementation of a tax structure satisfactory to us for the proposed transaction), other material contracts, litigation, regulatory, environmental and other similar customary matters. Assuming reasonable access to management and due diligence materials, we would expect our diligence to take 2-3 weeks.

Conditions Precedent

The execution of the Definitive Agreements would be subject to, among other things, the following conditions: (i) completion of due diligence to the satisfaction of BCEM in its sole discretion, (ii) approval of the final terms of the Definitive Agreements by the Investment Committee of BCEM, (iii) execution and delivery of the Definitive Agreements in form and substance acceptable to Alta Mesa and BCEM in their sole discretion, (iv) receipt of all necessary regulatory and third party consents and approvals, and (v) the release of liens, if any, held by the financial institutions participating in the Alta Mesa revolving credit agreement on all locations contributed to DrillCo.

Exclusivity & Closing

The work BCEM has performed over the last several months with respect to the Meramec assets uniquely positions it to move swiftly to a close and subsequent prosecution of the DrillCo development plan. As such, BCEM is committed to achieving a closing as early as 30 days post-execution of this Revised LOI. In consideration of our efforts and our incurring significant expenses with our due diligence review as discussed above, Alta Mesa agrees to suspend all discussions and other contacts with any other party with respect to any competing proposed or contemplated transactions with the Company, not to solicit, encourage or discuss any alternative proposals from other parties with respect to any such competing proposed or contemplated transactions, and to negotiate exclusively with us with respect to this Revised LOI for 30 days post-execution of the Revised LOI (the "Exclusive Period"). Further, during the Exclusive

Period, the Company agrees to notify us promptly upon receipt of any inquiries regarding the proposed acquisition of any substantial portion of the Company or its assets by any other party.

Please feel free to call me at 713.400.8210 if you have any questions or if you require any further information regarding this proposal. Please note that this Revised LOI will expire at close of business on July 14, 2015. I am, and continue to be, impressed by what Alta Mesa has achieved within the Sooner Trend and look forward to aiding in the acceleration of the development of this world class asset.

Sincerely,

William W. McMullen
Founder | Managing Partner
Bayou City Energy Management LLC

Acknowledged by Alta Mesa Holdings, LP Representative:
Alta Mesa Holdings, LP

By: ______________________________________

Option Elected: ____________________________

Bayou City Energy Partners, LP

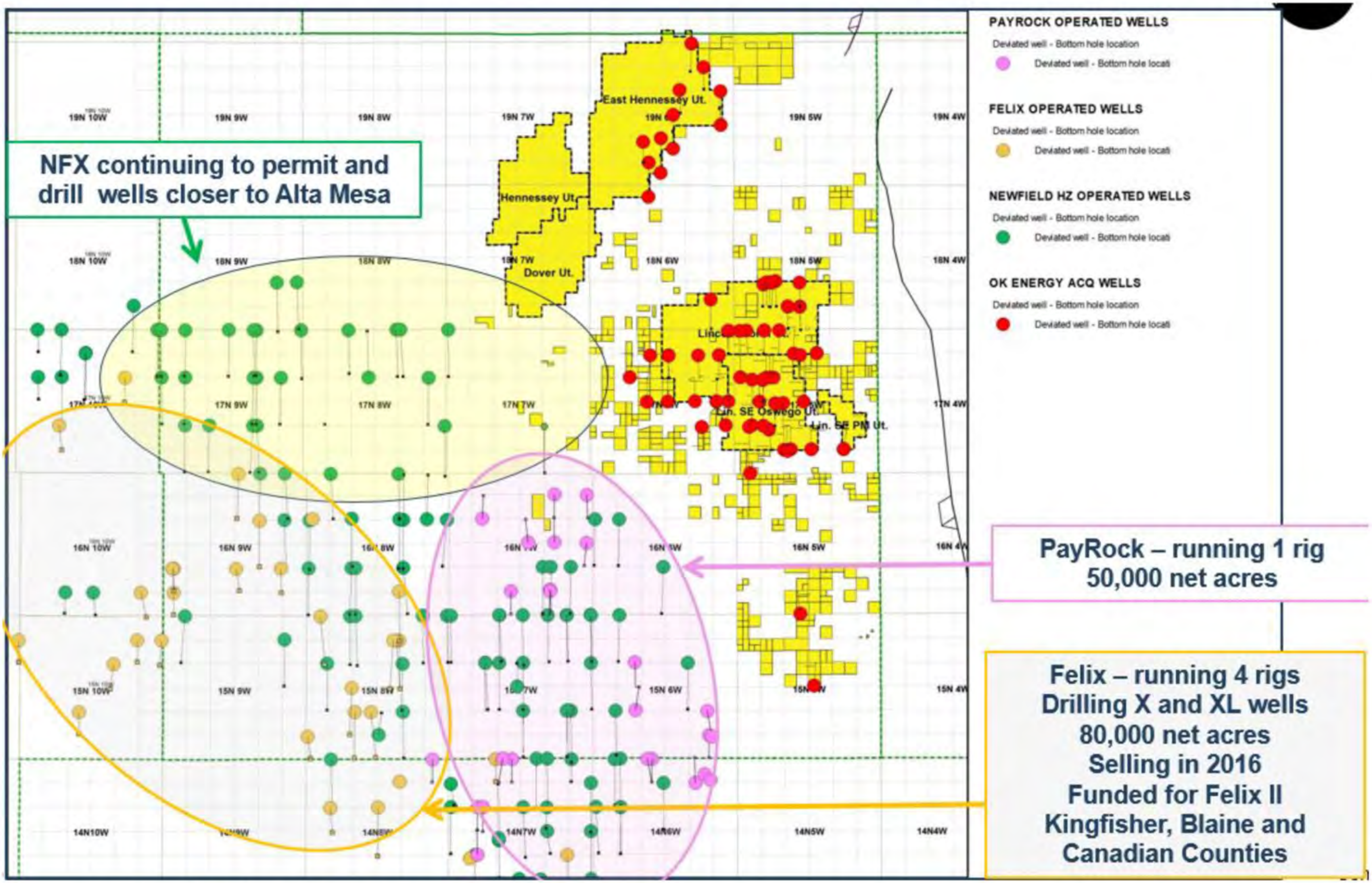
1221 McKinney Street, Suite 2875
Houston, TX 77010

Assessment of Kingfisher County, Oklahoma Horizontal Mississippian Assets of ***Alta Mesa Holdings, LP***

Prepared 12-29-15

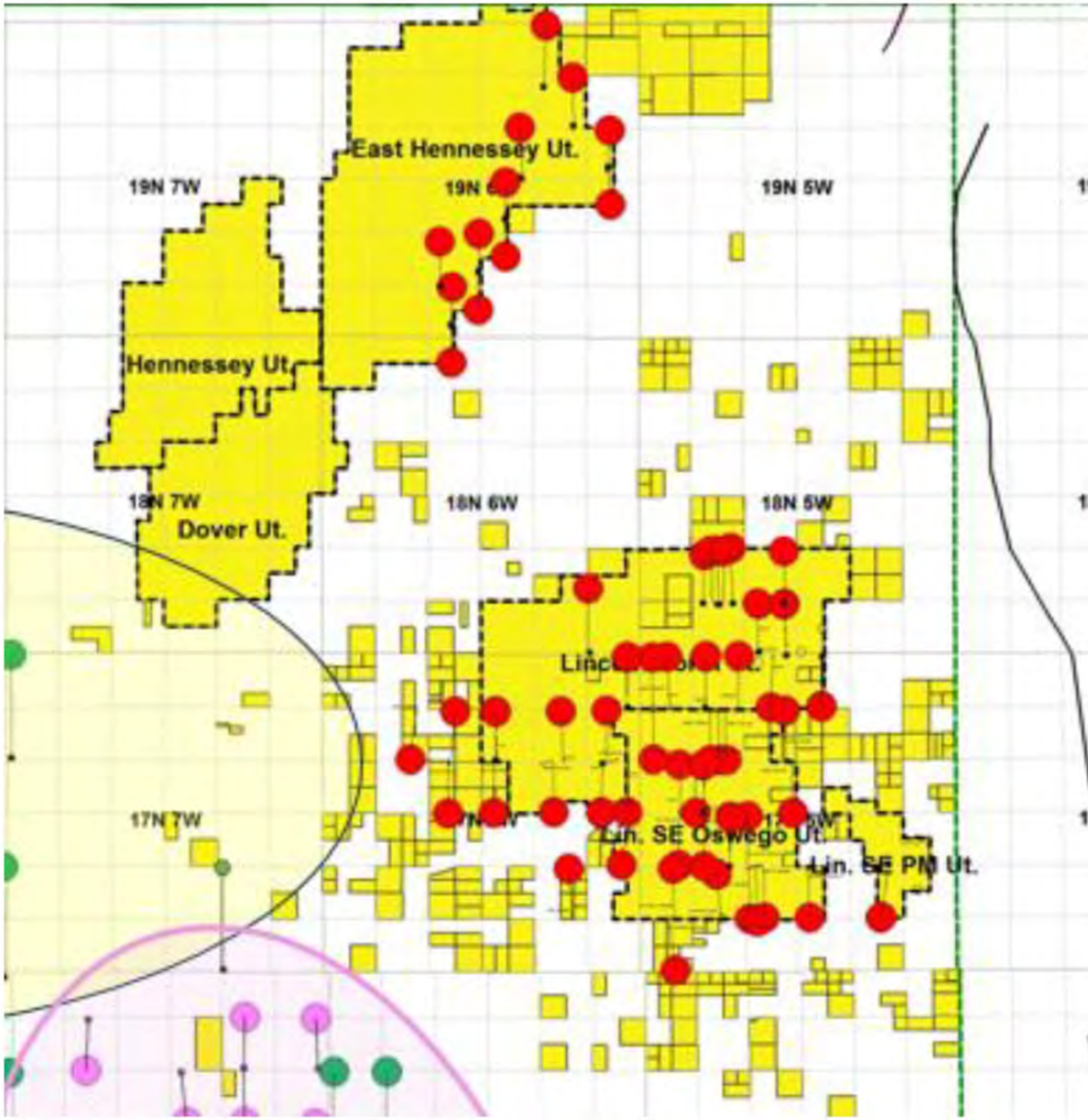
Pinnacle Energy Services, LLC
9420 Cedar Lake Ave, Oklahoma City, OK 73114
Ofc: 405-810-9151 www.PinnacleEnergy.com

Regional Area – Kingfisher County



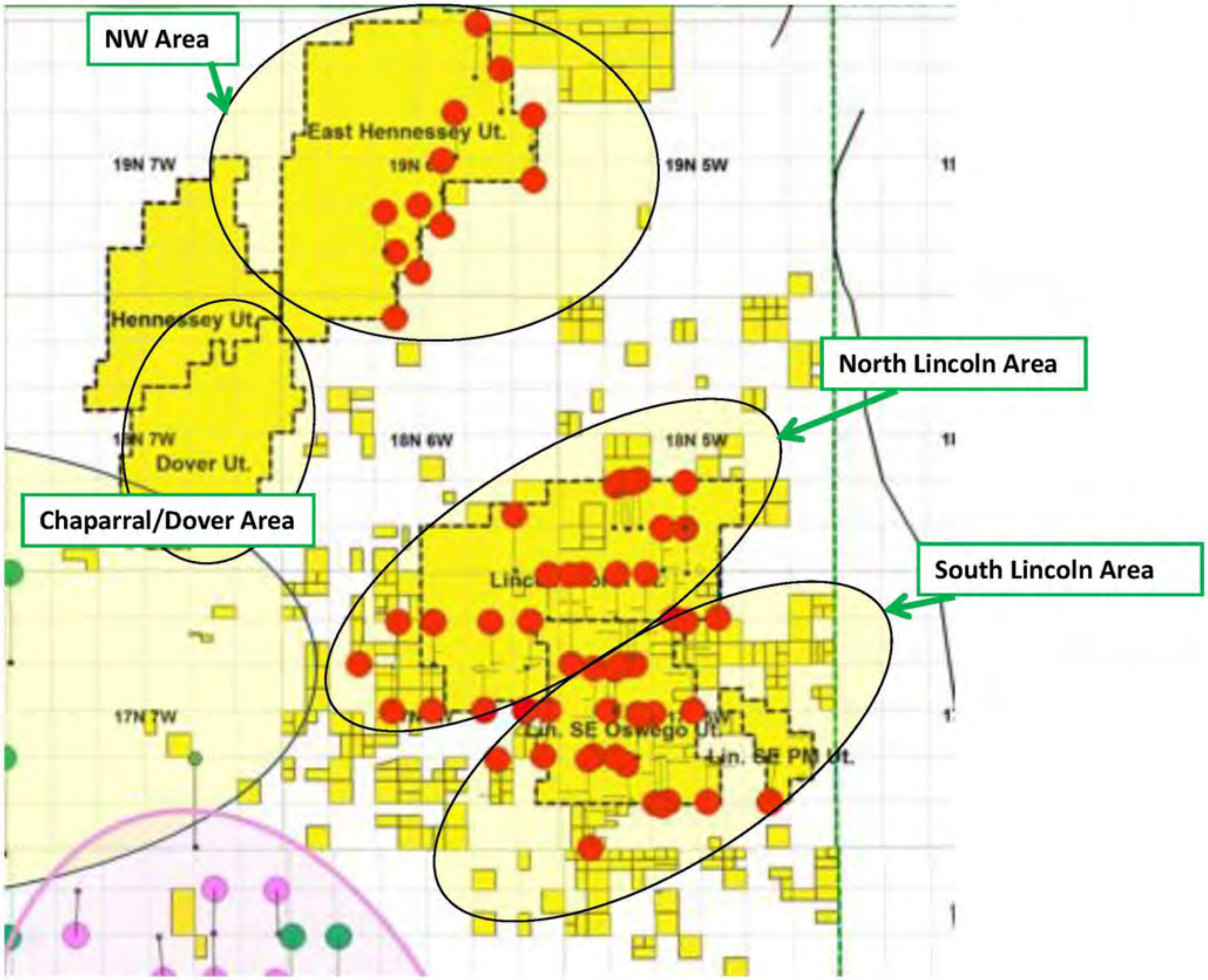
- From an Alta Mesa presentation

Northeastern Kingfisher County, Oklahoma – Alta Mesa AOI



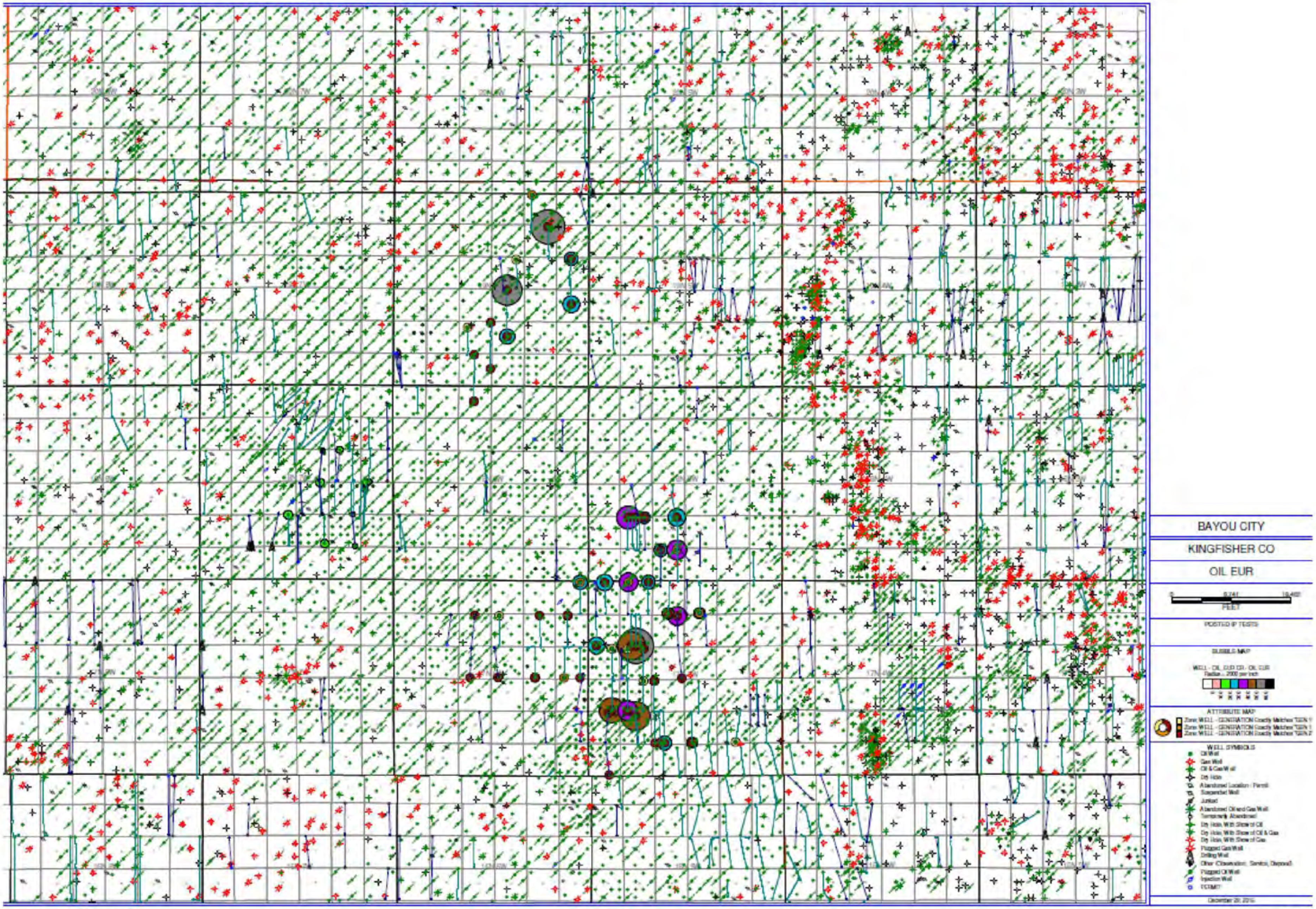
- From an Alta Mesa presentation

Regional Area – PES Nomencalture

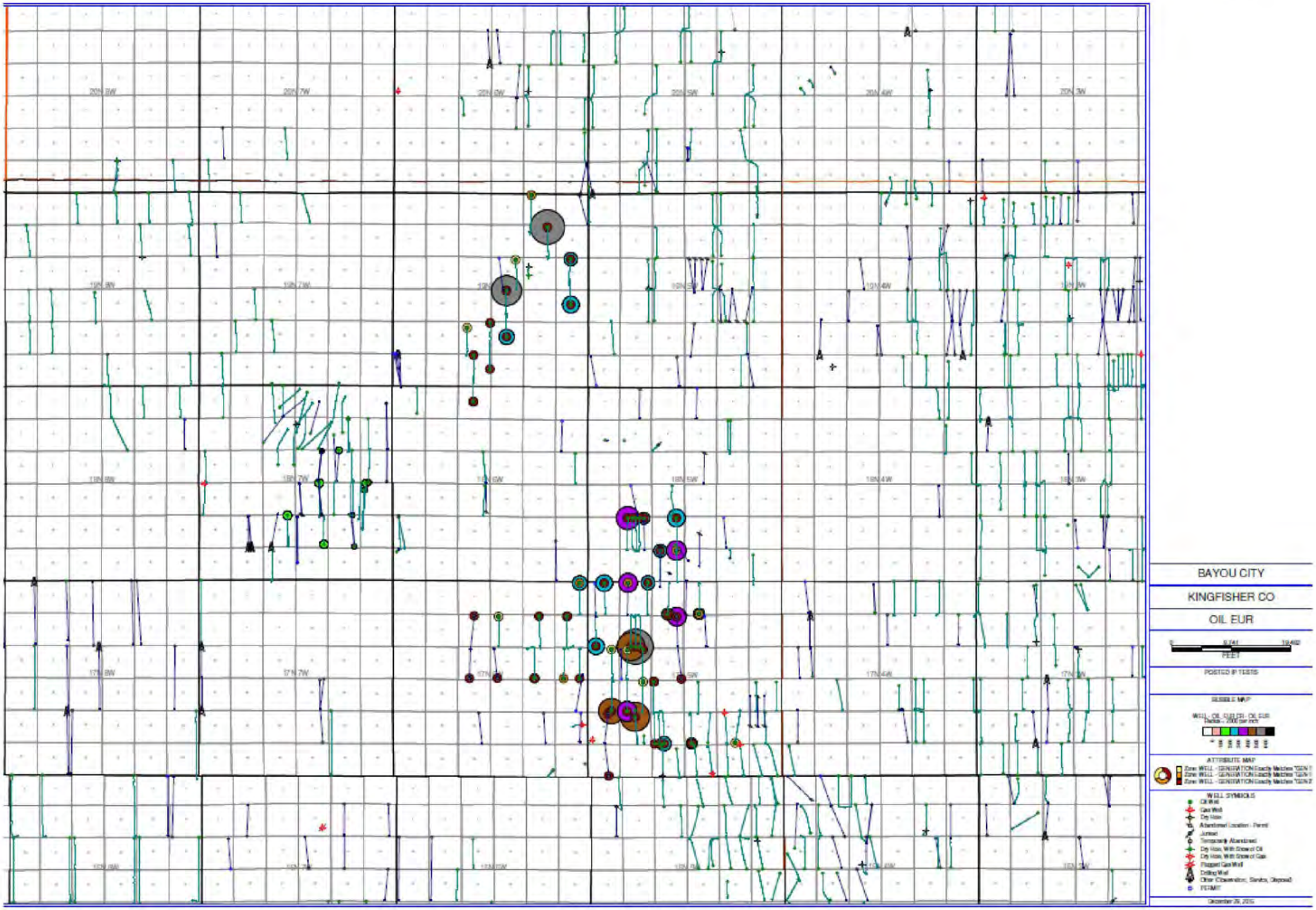


- From an Alta Mesa presentation

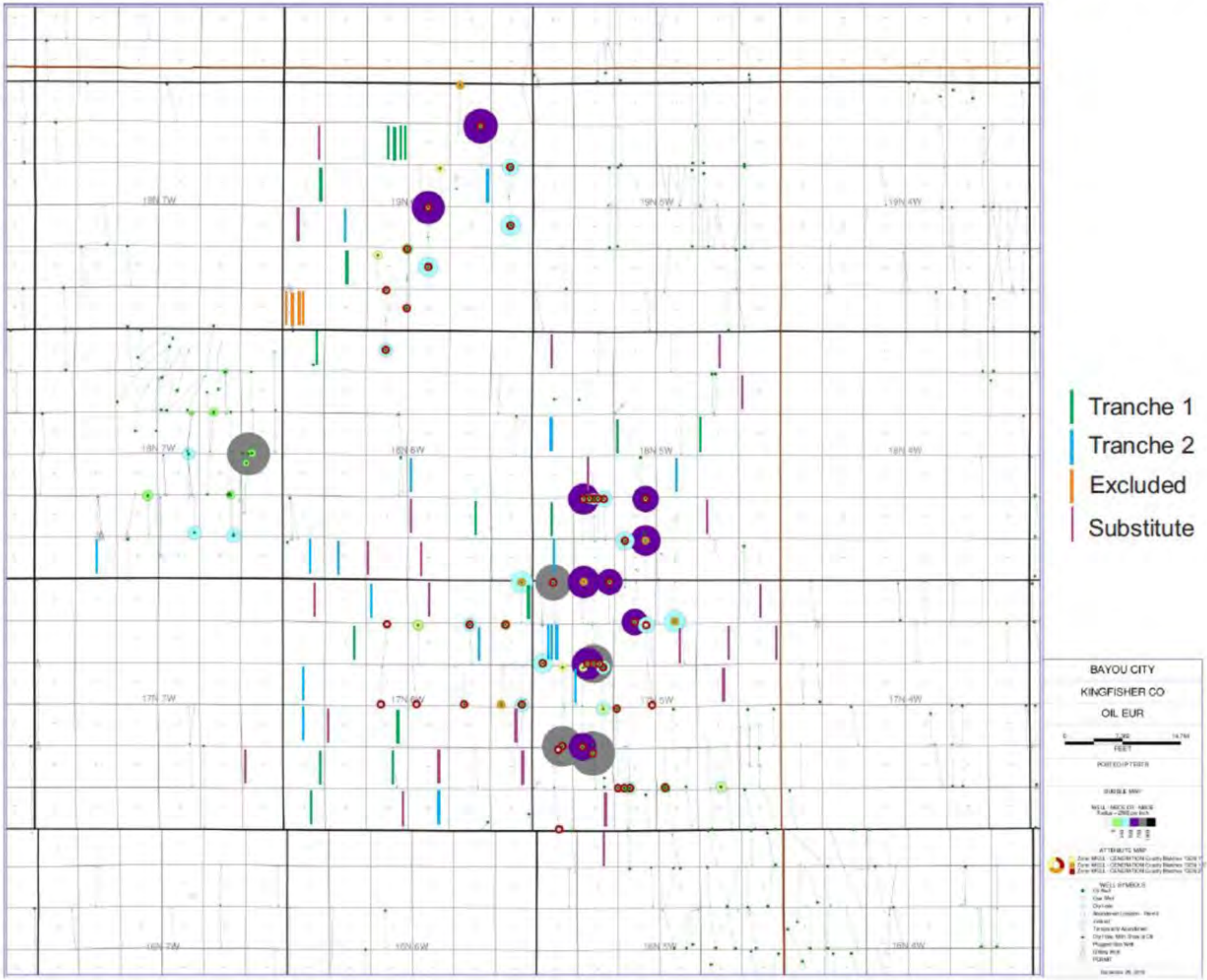
Bubble Map of Alta Mesa HZ Mississippian Wells with All Area Vertical and Horizontal Wells



Bubble Map of Alta Mesa HZ Mississippian Wells with All Area Horizontal Wells Only (Various Formations)



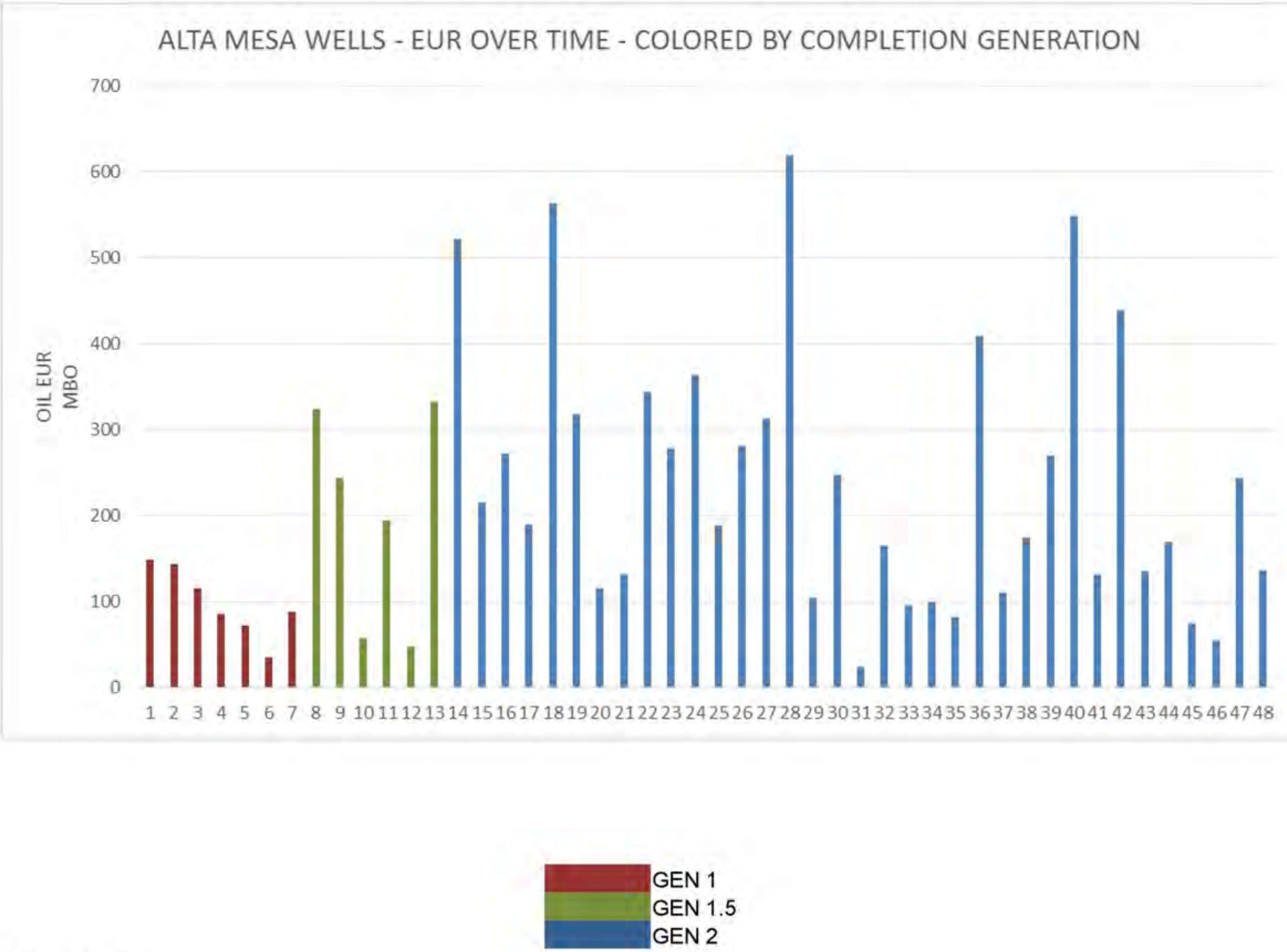
Bubble Map of Alta Mesa HZ Mississippian Wells Only with BCEP identified Future Alta Mesa Locations



Graphs comparing Oil EUR's By Area, Zone & Completion Order

Oil EURs – Alta Mesa Wells

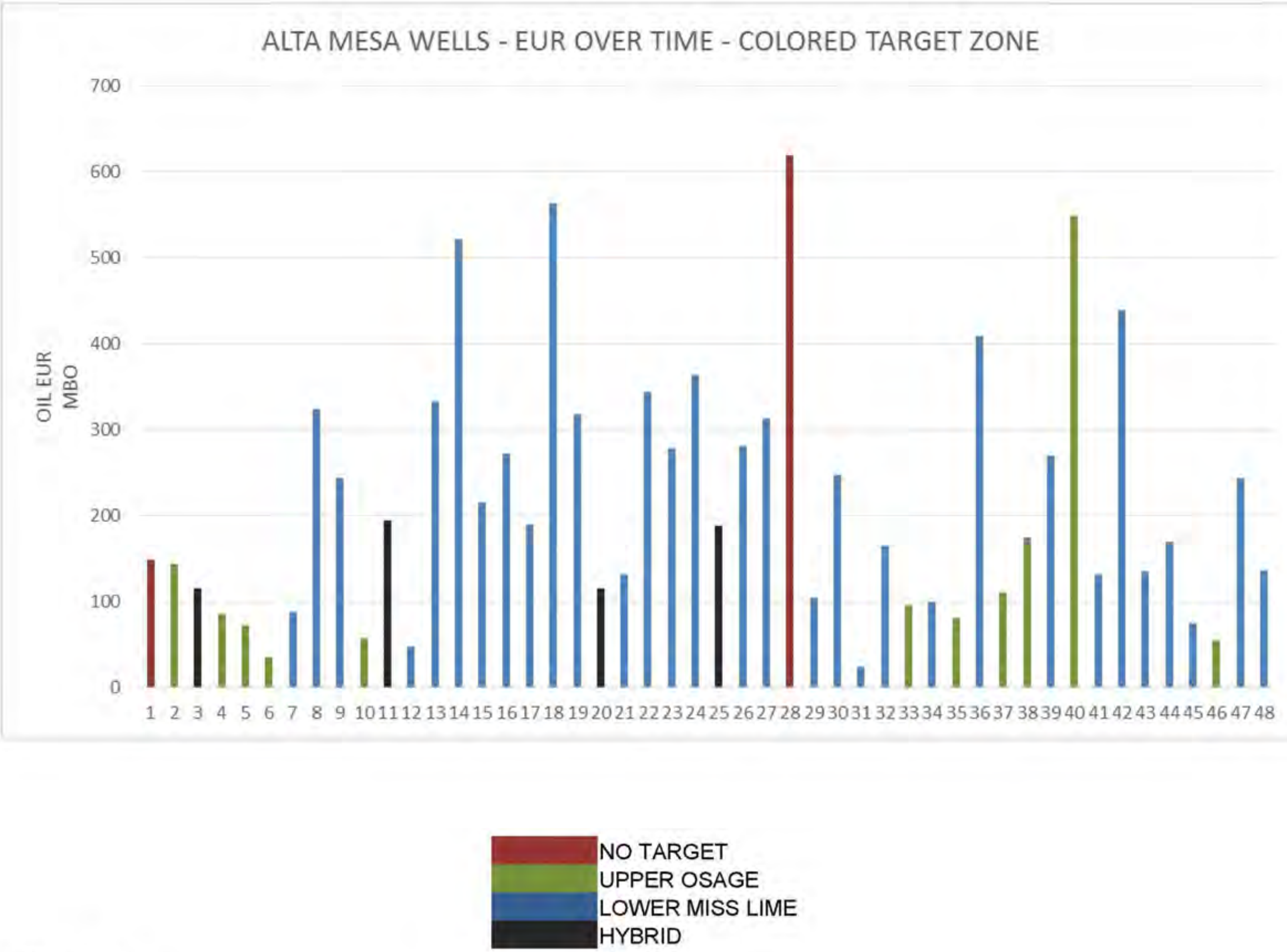
All Mississippian Wells – Normalized to 4500'



Determination of Completion Type/Generation based on information provided by Alta Mesa

Oil EURs – Alta Mesa Wells

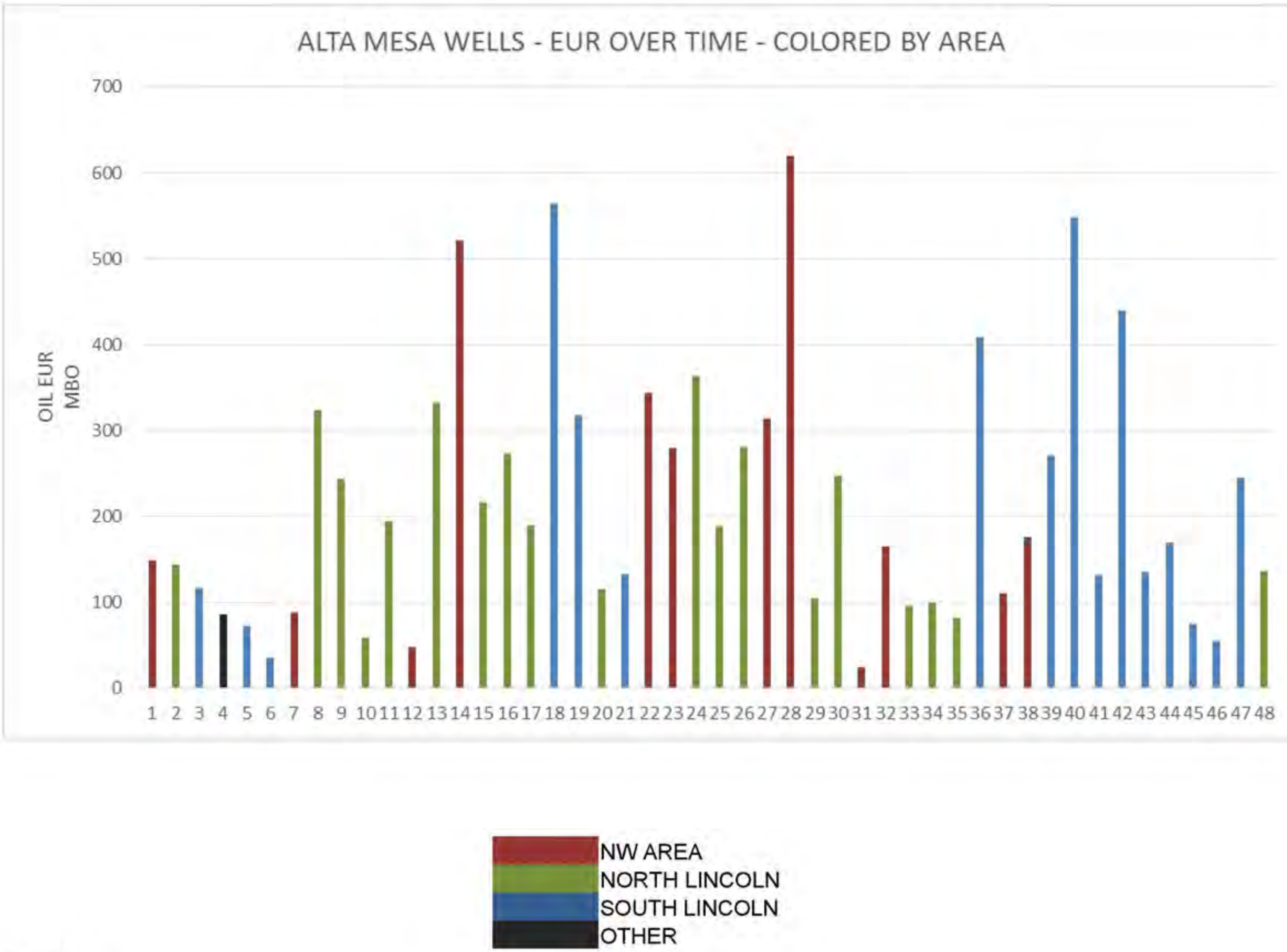
All Mississippian Wells – Normalized to 4500'



Determination of Targeted Mississippian Interval based on information provided by Alta Mesa

Oil EURs – Alta Mesa Wells

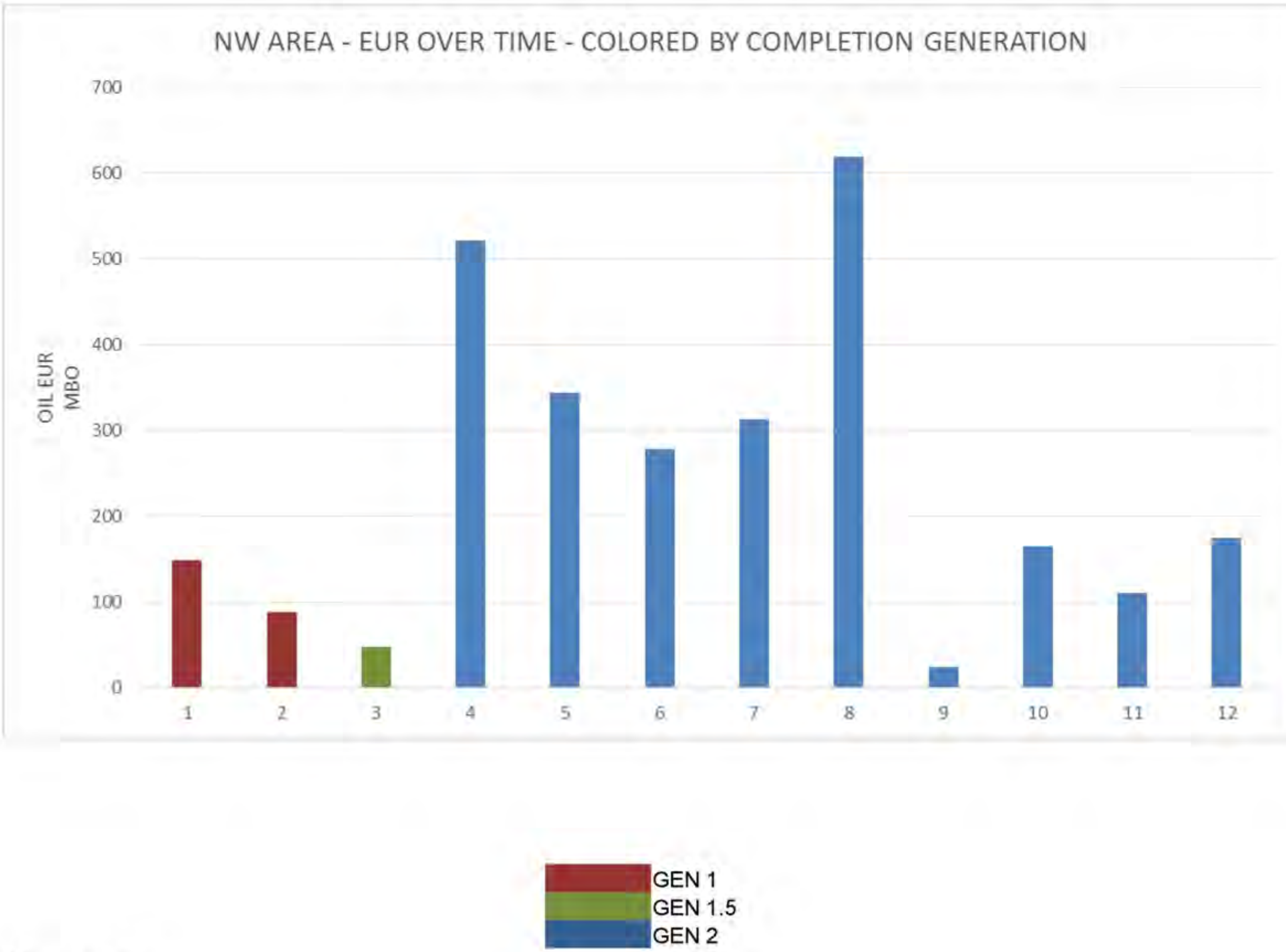
All Mississippian Wells – Normalized to 4500'



Grouped Areas were determined by PES based on location of Alta Mesa Wells

Oil EURs – Alta Mesa Wells

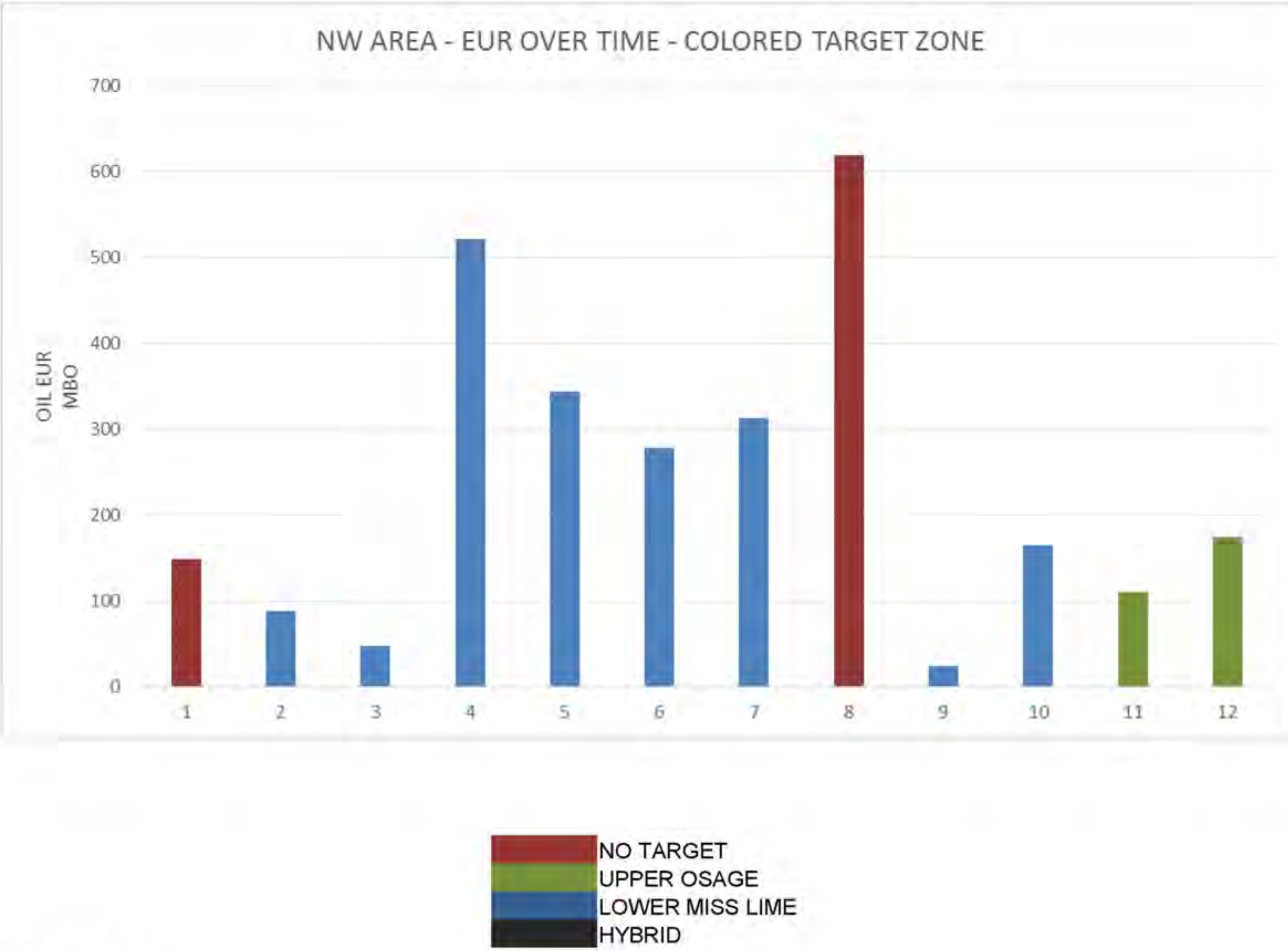
Northwest Area Mississippian Wells – Normalized to 4500'



Determination of Completion Type/Generation based on information provided by Alta Mesa

Oil EURs – Alta Mesa Wells

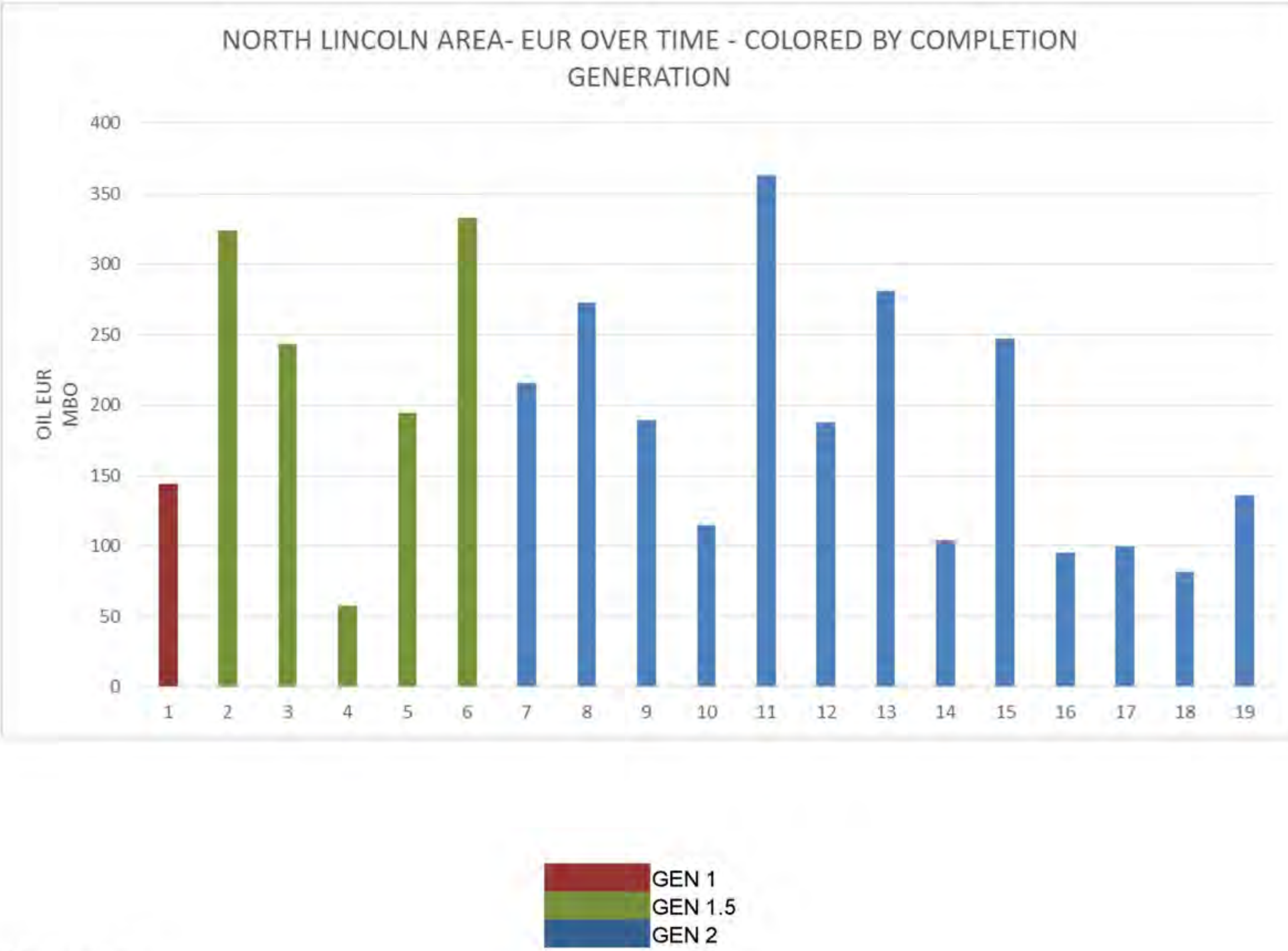
Northwest Area Mississippian Wells – Normalized to 4500'



Determination of Targeted Mississippian Interval based on information provided by Alta Mesa

Oil EURs – Alta Mesa Wells

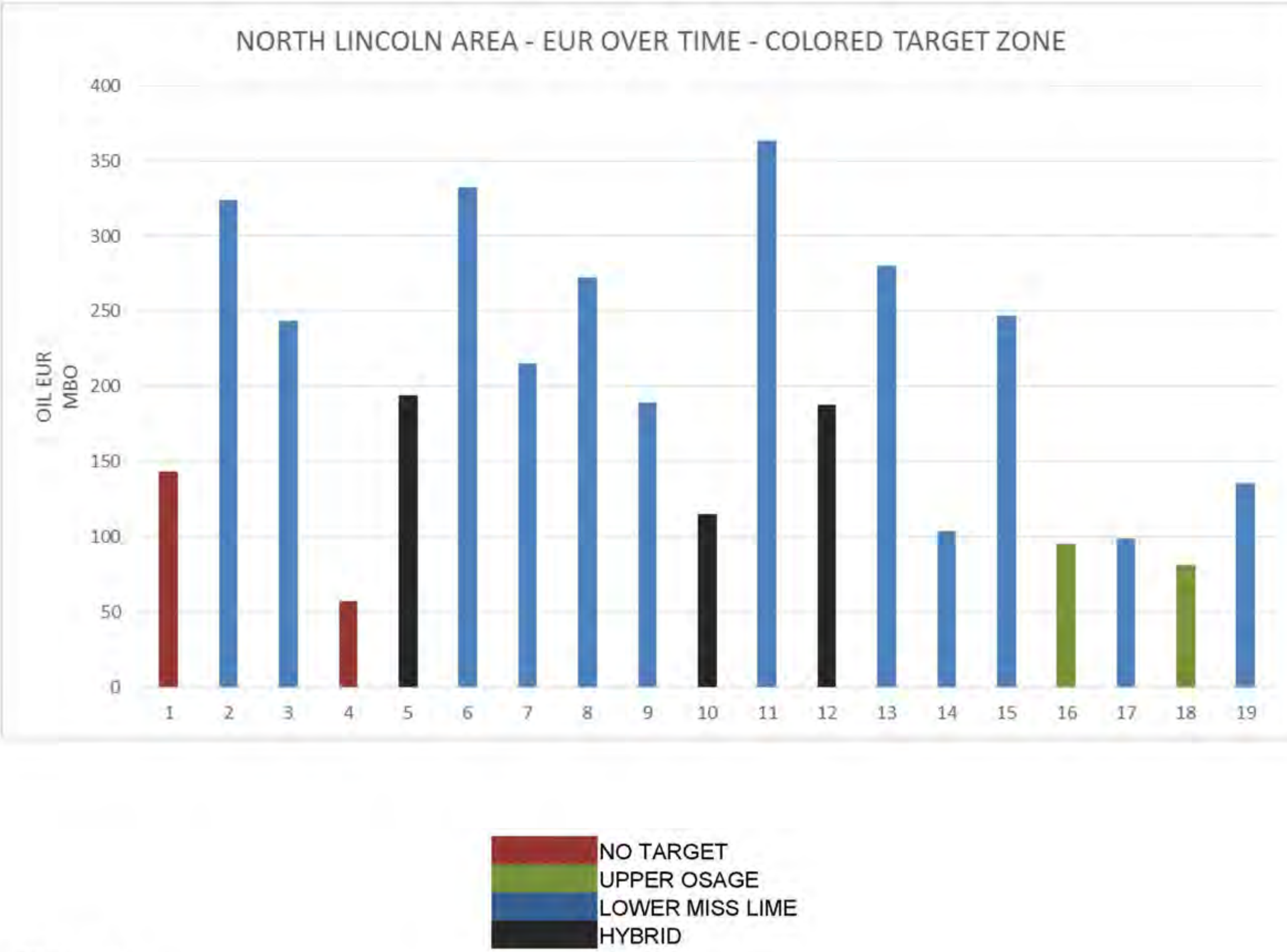
North Lincoln Area Mississippian Wells – Normalized to 4500'



Determination of Completion Type/Generation based on information provided by Alta Mesa

Oil EURs – Alta Mesa Wells

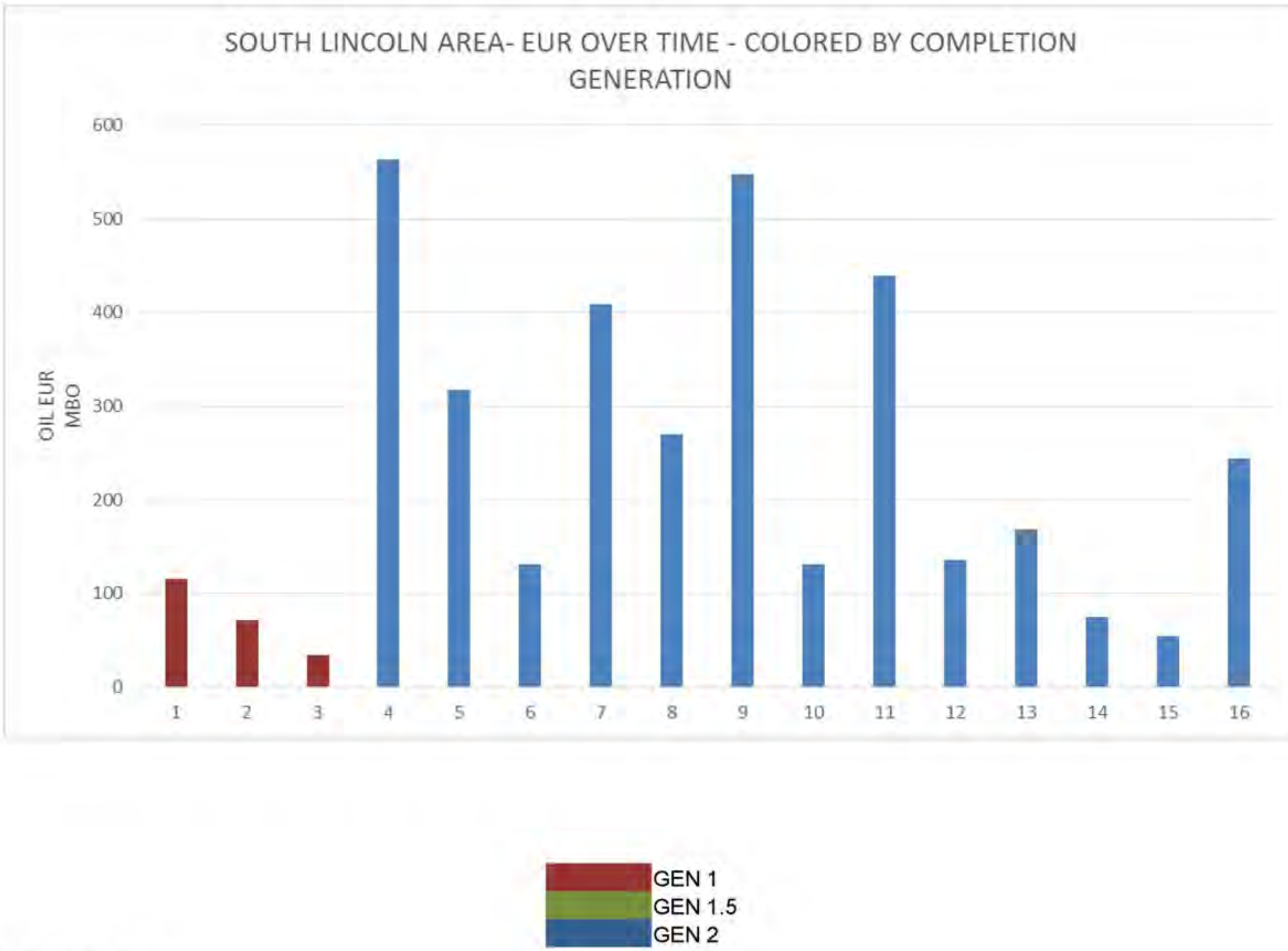
North Lincoln Area Mississippian Wells – Normalized to 4500'



Determination of Targeted Mississippian Interval based on information provided by Alta Mesa

Oil EURs – Alta Mesa Wells

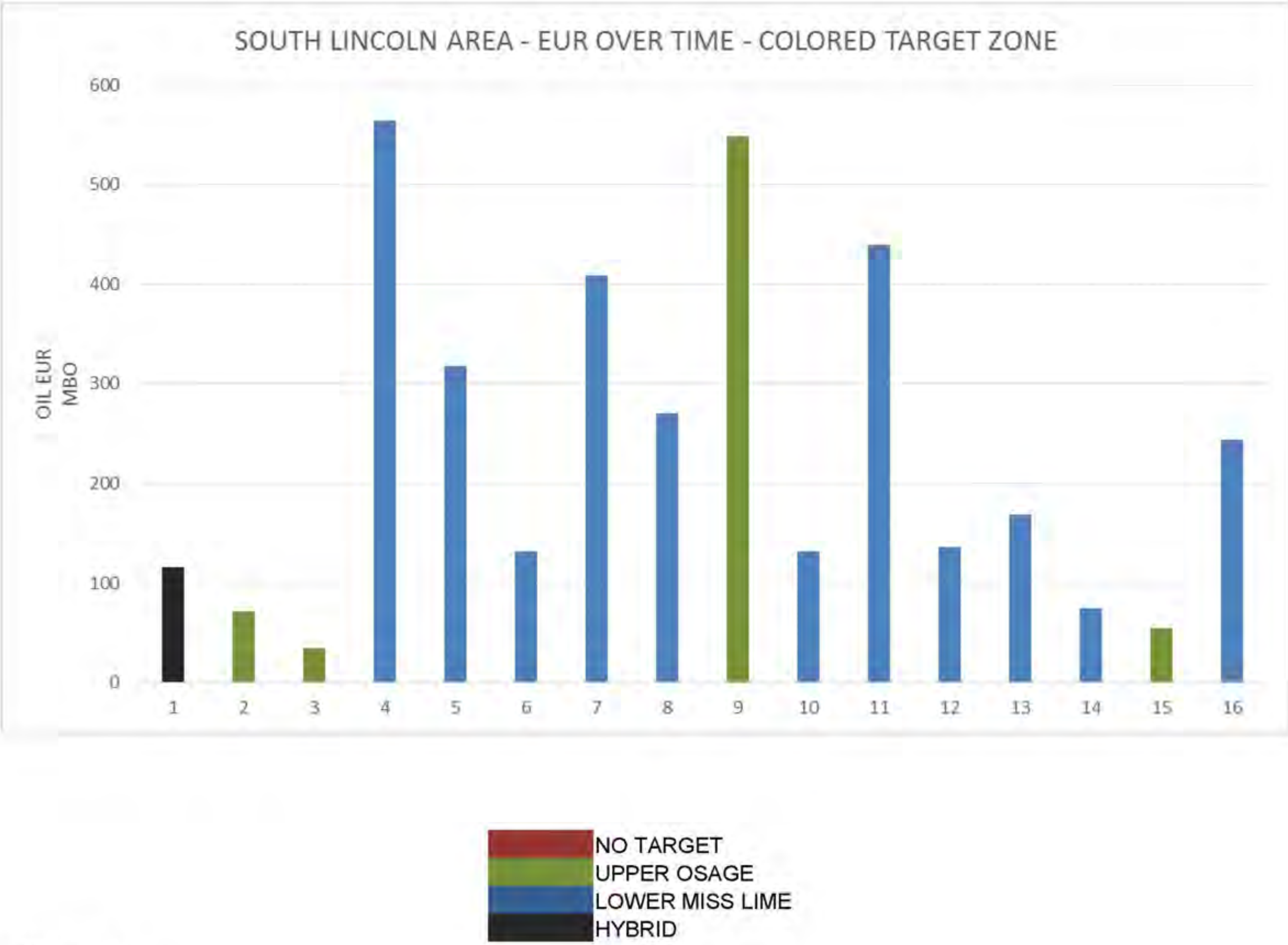
South Lincoln Area Mississippian Wells – Normalized to 4500'



Determination of Completion Type/Generation based on information provided by Alta Mesa

Oil EURs – Alta Mesa Wells

South Lincoln Area Mississippian Wells – Normalized to 4500'



Determination of Targeted Mississippian Interval based on information provided by Alta Mesa

Oil EURs – Probability & Statistics

Oil EURs – Probability & Statistics

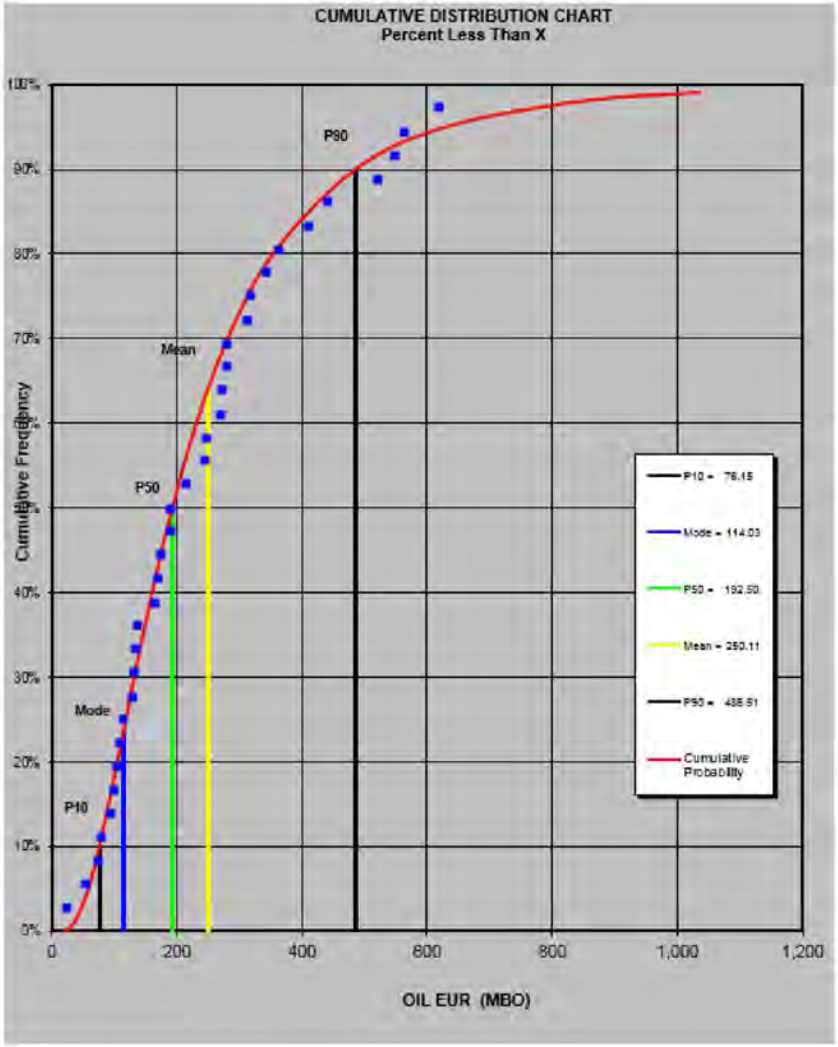
Summary of “Gen 2” Alta Mesa Horizontal Mississippian Wells EURs along with Chaparral, Dorado, Longfellow HZ Mississippian Wells Normalized to 4500’

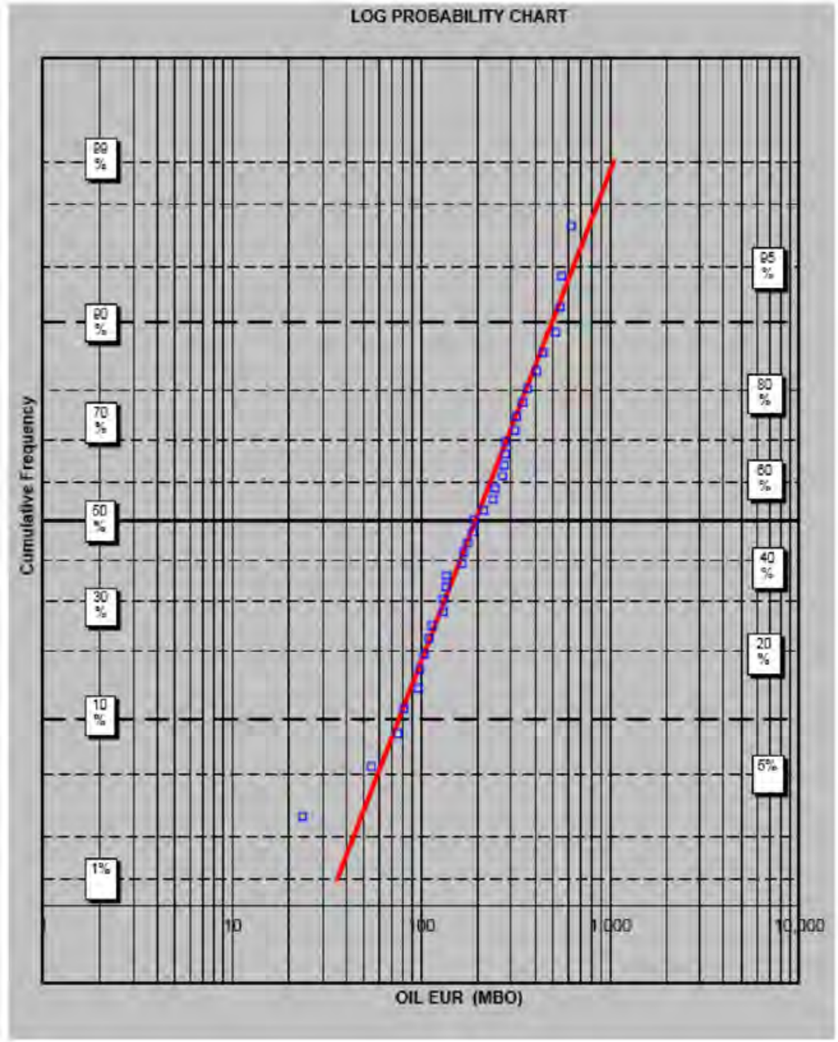
<table>
<tr><th rowspan="4">GEN 2 WELLS</th><th colspan="8">PES</th><th colspan="3">AM</th></tr>
<tr><th colspan="4">ACTUAL EURs</th><th colspan="4">NORM TO 4500'</th><th rowspan="3">WELL COUNT</th><th rowspan="2">SWANSON'S MEAN</th><th rowspan="3">OIL P90/P10</th></tr>
<tr><th colspan="3">SWANSON'S MEAN</th><th rowspan="2">Oil P90/P10</th><th colspan="3">SWANSON'S MEAN</th><th rowspan="2">Oil P90/P10</th></tr>
<tr><th>WELL COUNT</th><th>OIL (MBO)</th><th>GAS (MMCF)</th><th>WELL COUNT</th><th>OIL (MBO)</th><th>GAS (MMCF)</th><th>OIL (MBO)</th></tr>
<tr><td>ALL WELLS</td><td>37</td><td>245.19</td><td>1149.05</td><td>6.3</td><td>35</td><td>250.11</td><td>1248.14</td><td>6.4</td><td>28</td><td>242</td><td>3.6</td></tr>
<tr><td>NW AREA WELLS</td><td>9</td><td>295.80</td><td>971.06</td><td>13.6</td><td>9</td><td>337.39</td><td>1134.17</td><td>12.5</td><td>9</td><td>249</td><td>2.0</td></tr>
<tr><td>NORTH LINCOLN AREA</td><td>14</td><td>188.54</td><td>1340.07</td><td>3.3</td><td>13</td><td>185.67</td><td>1389.92</td><td>3.5</td><td rowspan="2">19</td><td rowspan="2">242</td><td rowspan="2">4.7</td></tr>
<tr><td>SOUTH LINCOLN AREA</td><td>14</td><td>289.03</td><td>1055.43</td><td>6.2</td><td>13</td><td>281.75</td><td>1165.82</td><td>6.8</td></tr>
<tr><td>CHAPARRAL WELLS</td><td>12</td><td>104.35</td><td>848.46</td><td>2.3</td><td>9</td><td>96.17</td><td>768.39</td><td>2.9</td><td></td><td></td><td></td></tr>
<tr><td>NE AREA WELLS</td><td>16/14</td><td>128.77</td><td>807.58</td><td>3.8</td><td>15/13</td><td>151.61</td><td>935.05</td><td>4.0</td><td></td><td></td><td></td></tr>
</table>

PES – Pinnacle Energy Services Calculated Results
AM – Alta Mesa reported Results

Oil EURs – Probability & Statistics

All Gen 2 Alta Mesa Mississippian Wells – Normalized to 4500'

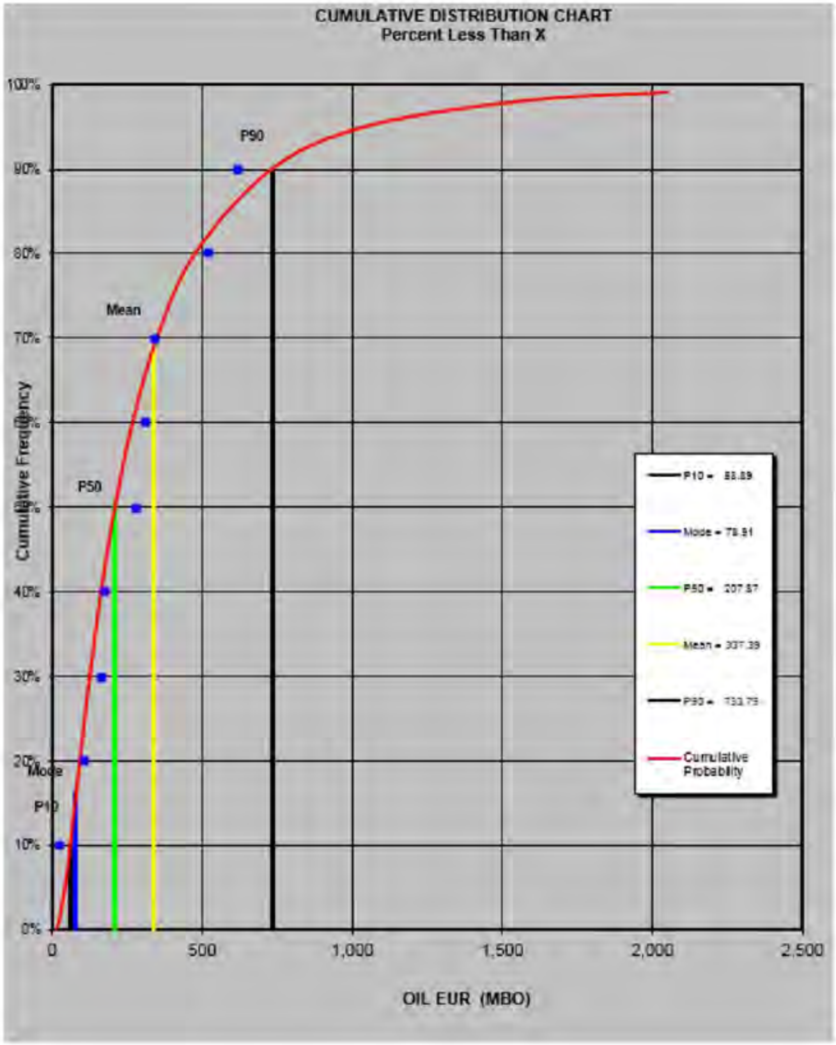


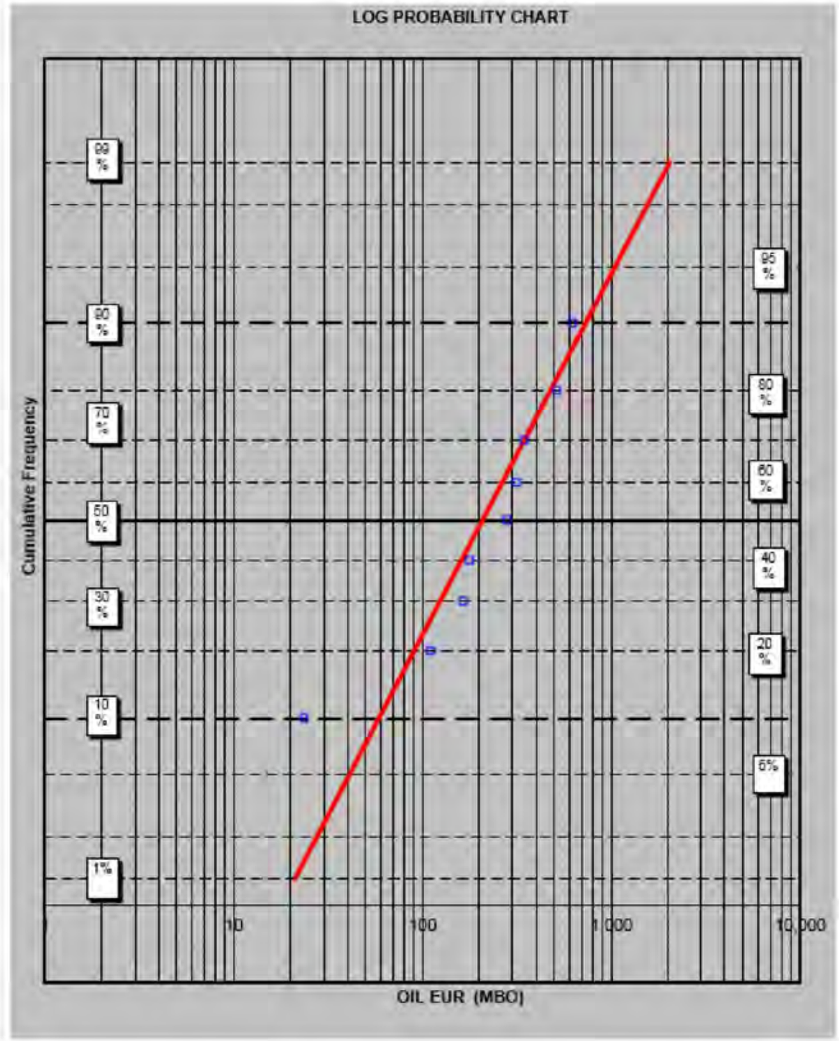


P90/P10 = 6.4

Oil EURs – Probability & Statistics

NW Area Gen 2 Alta Mesa Mississippian Wells – Normalized to 4500'

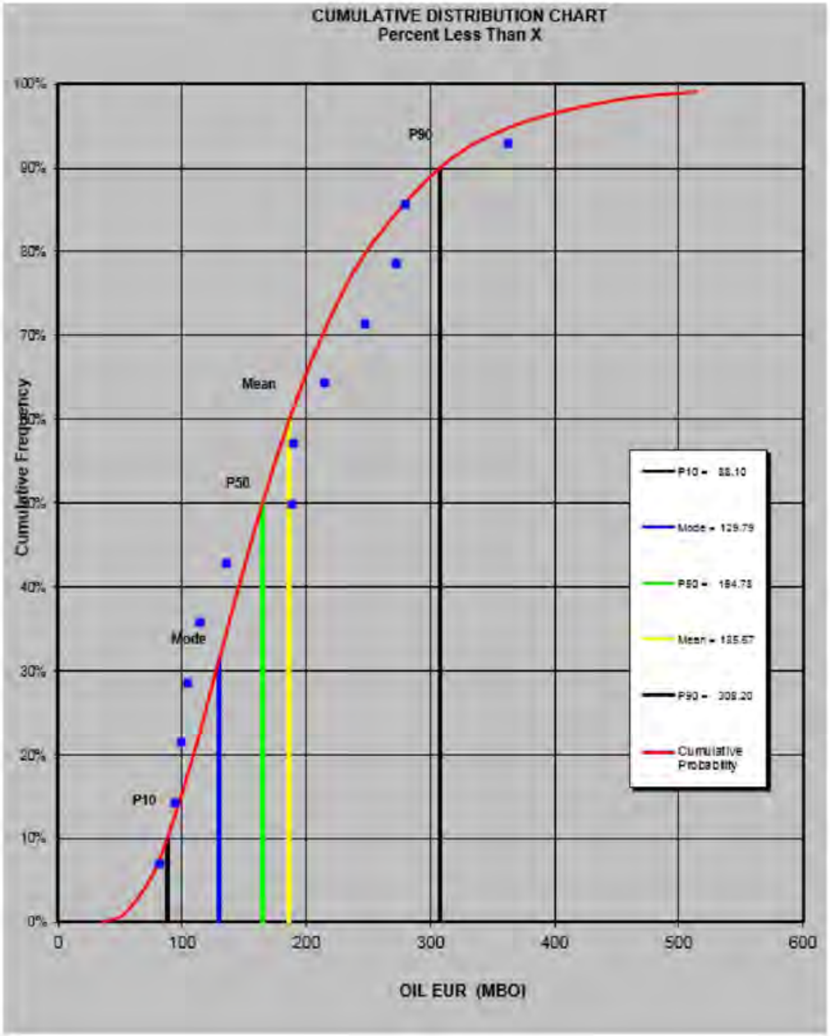


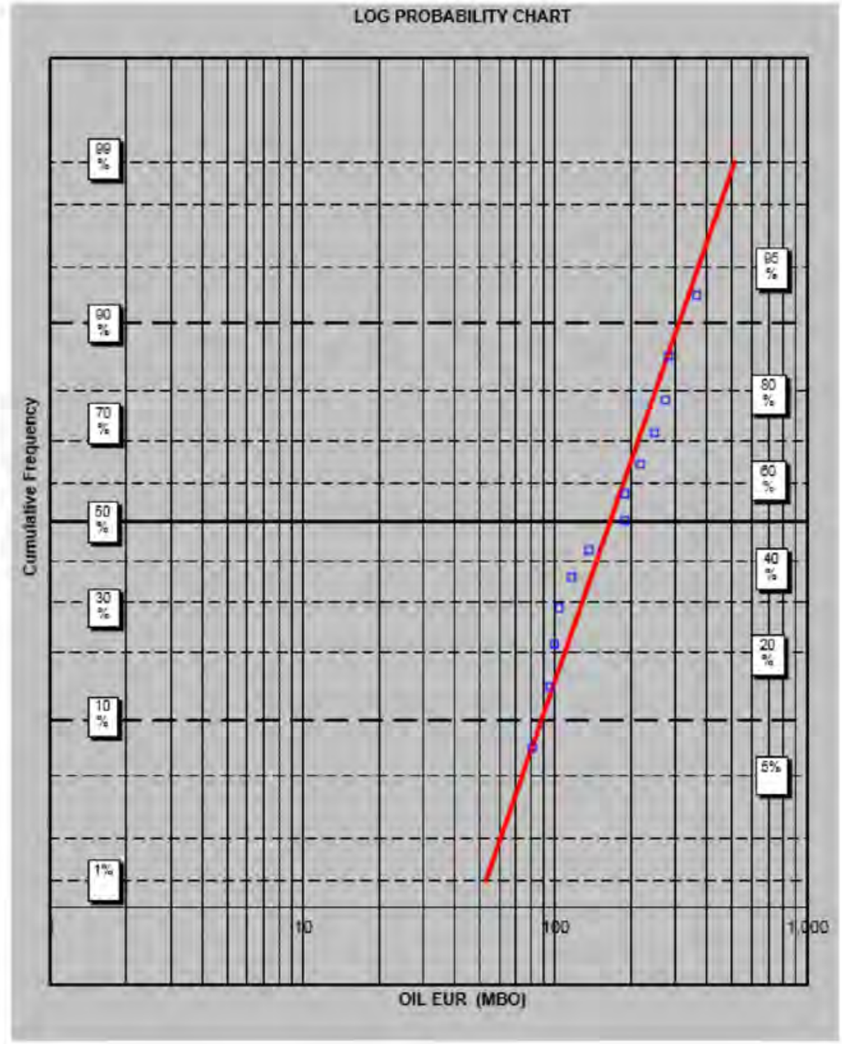


P90/P10 = 12.5

Oil EURs – Probability & Statistics

North Lincoln Area Gen 2 Alta Mesa Mississippian Wells – Normalized to 4500’

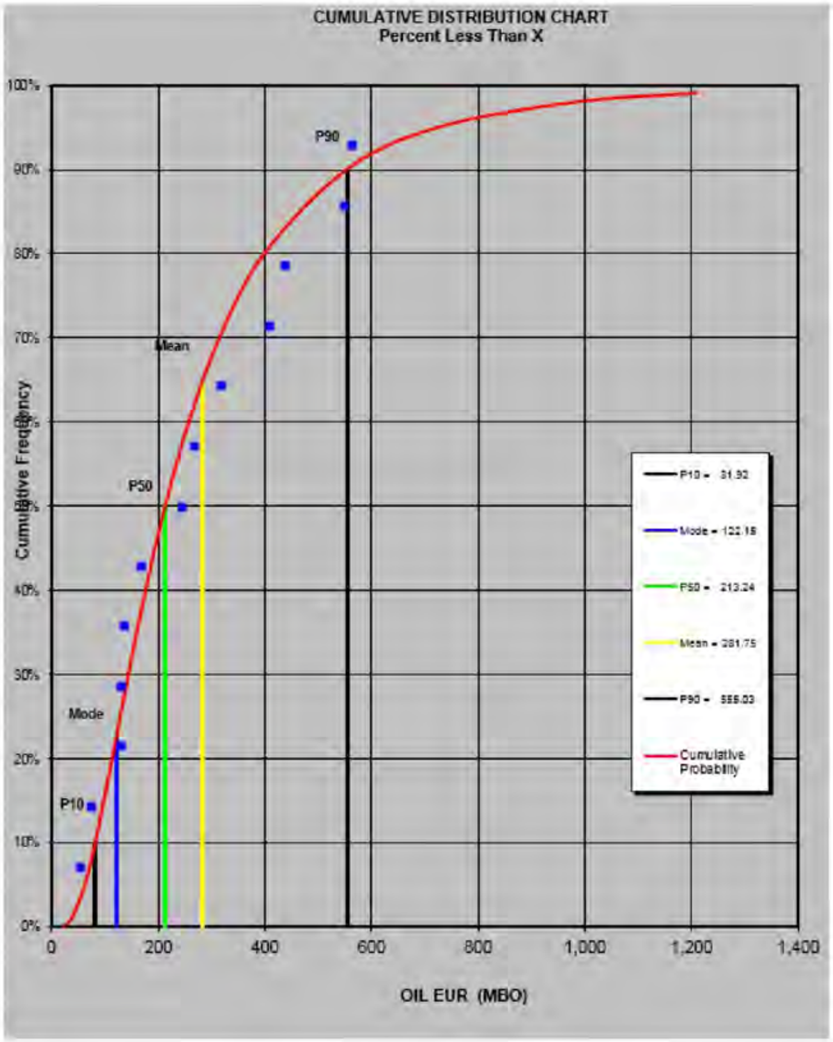


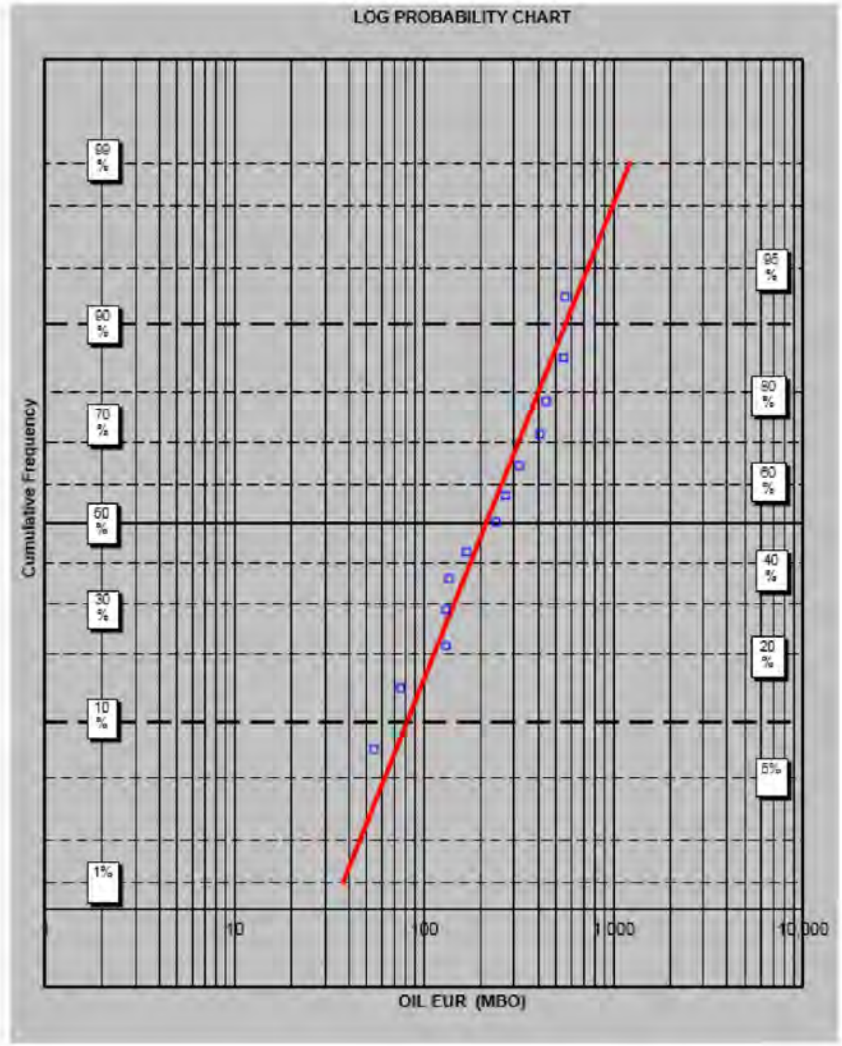


P90/P10 = 3.5

Oil EURs – Probability & Statistics

South Lincoln Area Gen 2 Alta Mesa Mississippian Wells – Normalized to 4500'

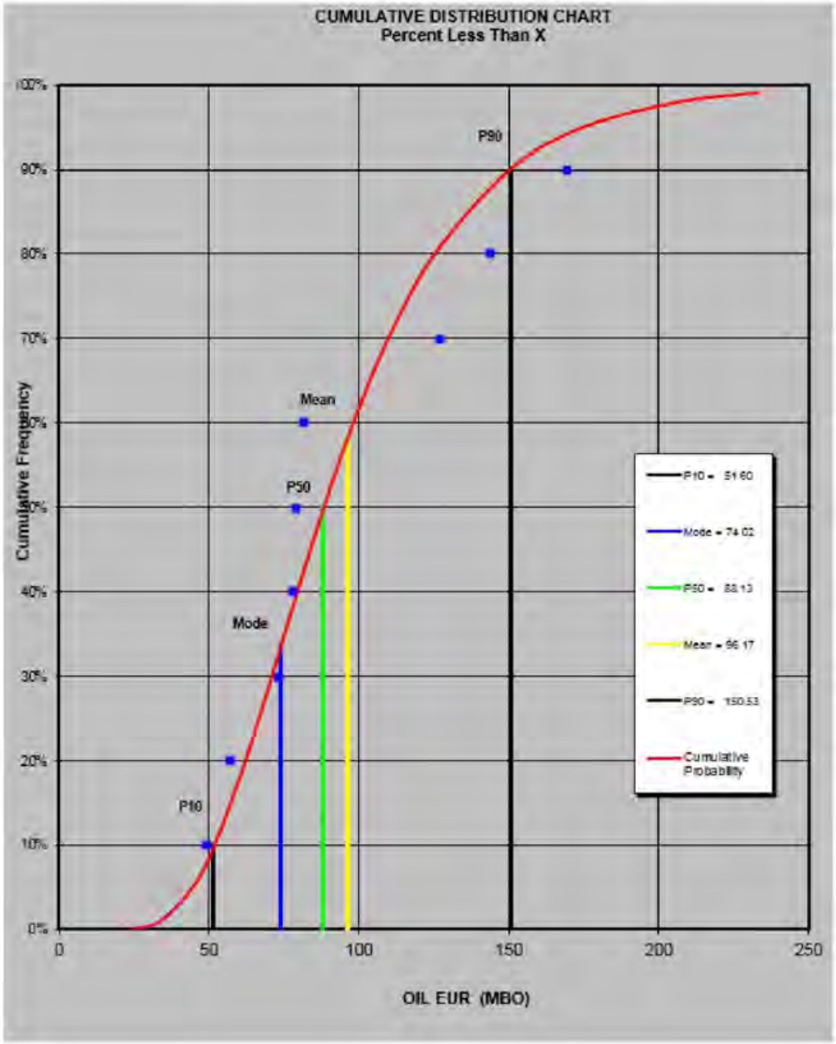


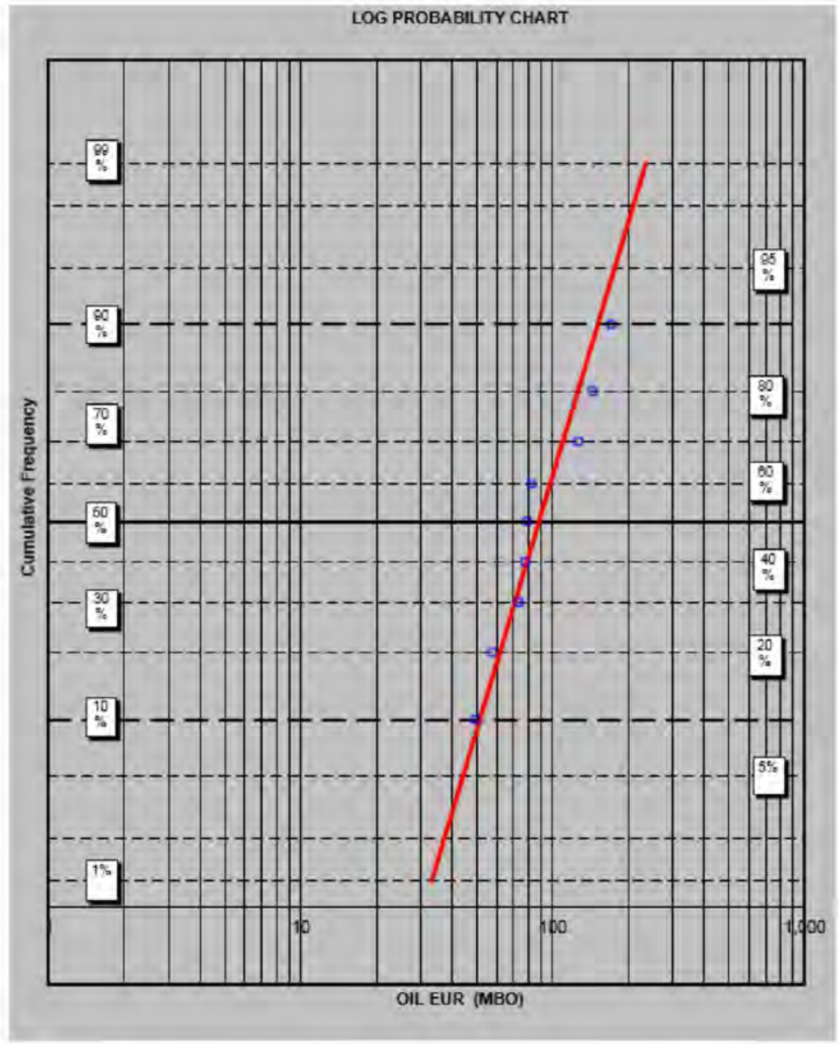


P90/P10 = 6.8

Oil EURs – Probability & Statistics

All Chaparral Kingfisher County Mississippian Wells – Normalized to 4500'

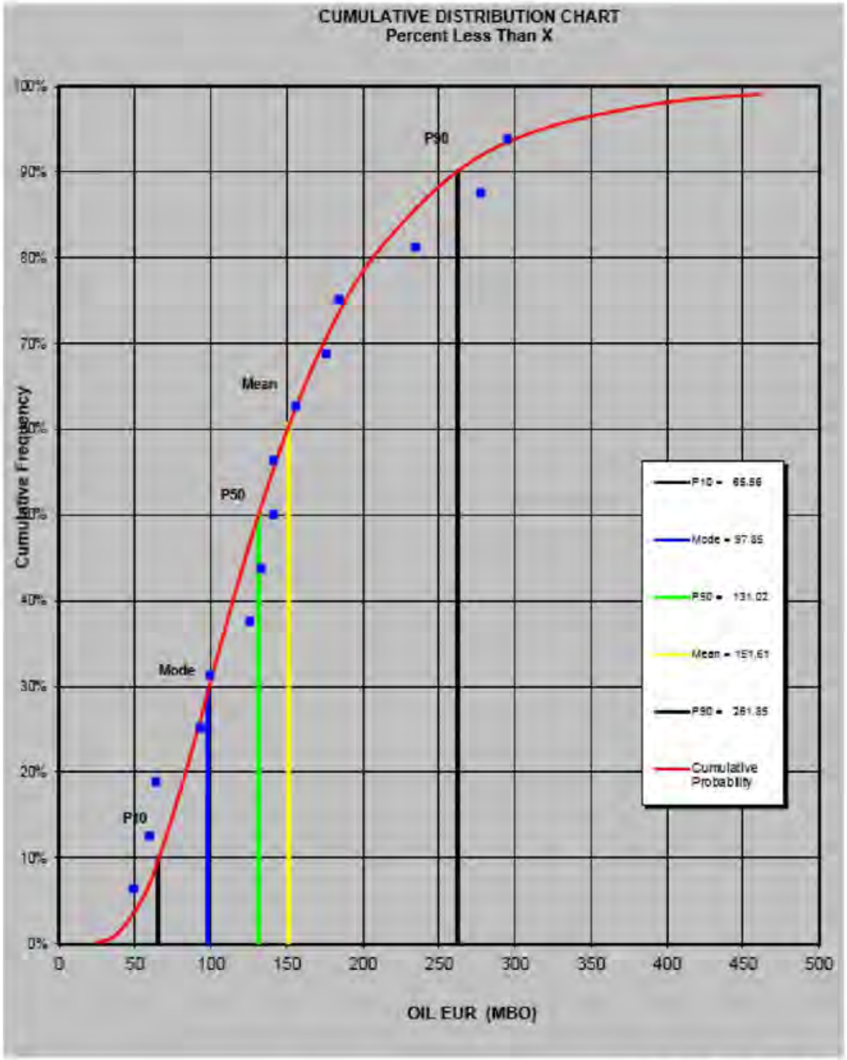


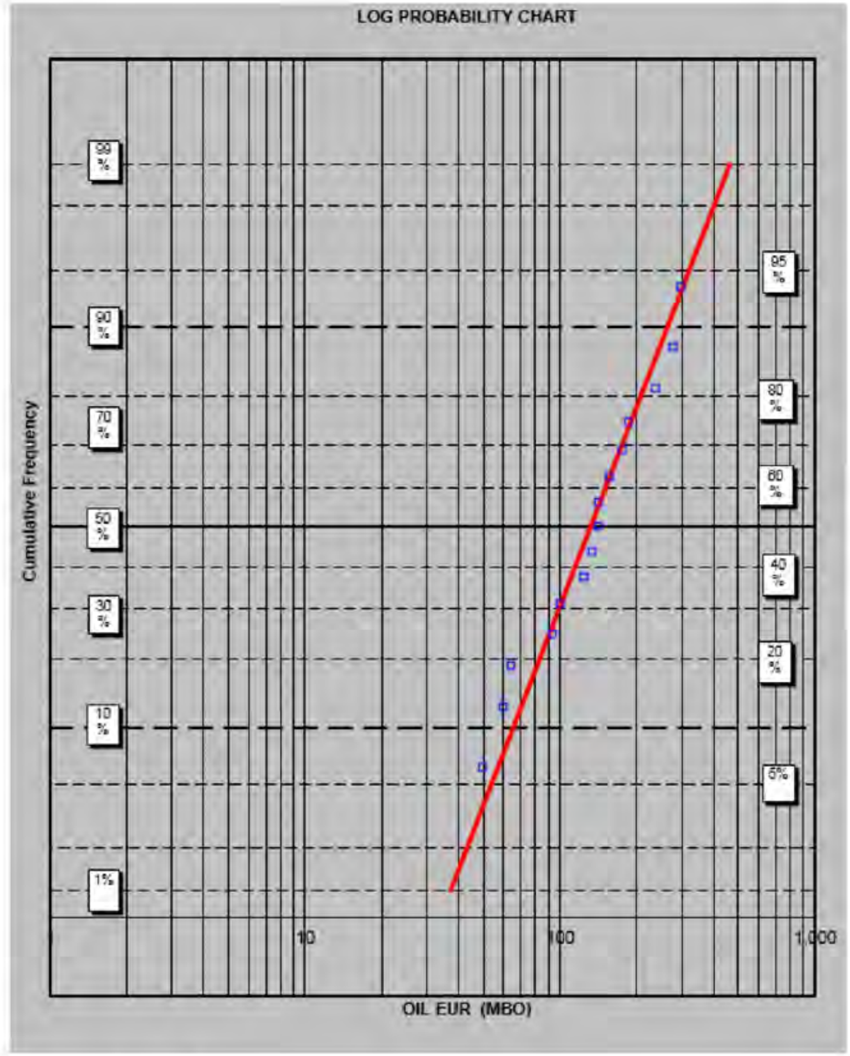


P90/P10 = 2.9

Oil EURs – Probability & Statistics (Dorado & Longfellow)

NE Area Mississippian Wells – Normalized to 4500'





P90/P10 = 4.0

Type Curve Economics

12/2015 NYMEX Pricing
MM$3.20 AFE
35% Shrink
106 BBL/MMCF Yield

Well Economics - Summary

Type Curve Economics

Composite TC - Alta Mesa

Details

Well Name	**250 MBO & 1250 MMCF**
Operator	ALTA MESA
Location	
Formation	MISSISSIPPIAN
Project	BAYOU CITY

Input Parameters	
Working Interest	100.000%
Net Revenue Interest	83.000%

Return Analysis	
IRR	92.9%
ROI	3.23x

Well Rates, Decline Parameters, Reserves

	1st Day Daily	1st Mo Ave	Hyperb b-Fact	De (Aries)	De (Phdw)	Dmin %	Gross EUR	Net EUR BBls.
Oil	692	480	1.00	65.48%	99.5000%	5.0%	250,722	208,099
Gas	1,935	1,596	1.00	55.26%	92.2000%	5.0%	1,251,630	675,255
NGL								110,118
MBOE							459,326.67	381,241
MMcfe							2,756	2,287
Water		-	1.0	65.484	99.5%	5.0%	-	

Operating Expenses

Fixed ($/Mo) Esc%	$	5,000.0
Variable:		
Oil ($/Bbl)	$	4.00
Gas ($/Mcf)	$	0.10
Other / Water ($/Bbl)	$	-
Oil Cut (%)		100.0%

Natural Gas Processing

Shrink	35.0%	
Yield	106.0	BBl/MMcf
Yield	4.5	Gal/Mcf

Pricing

	Initial	Max	% Esc
Oil	$ 45.48	$ 59.03	
Gas	2.43	4.22	
NGL	-	-	

Sev / Ad Valorem Tax

	Initial	Months	Final
Oil	2.00%	36	7.10%
Gas	2.00%	36	7.10%
NGL	2.00%	36	7.10%
Ad Valorem	0.00%	0	0.00%

Economic Results, M$

Net Cumulative Revenue, M$								
Oil	Gas	NGL	Total	Net Opex	let Sev Ta	Net Capita	Net Inc	Net PV10
$ 10,178.1	$ 2,163.8	$ 2,053.2	$ 14,395.1	$ 3,368.0	$ 682.3	$ 3,200.0	$ 7,144.8	$ 3,889.5

Finding C	Gross	Net
$/MBOE	$ 6.97	$ 8.39
$/MMcfe	$ 1.16	$ 1.40

Disc Rate	M$	Disc Rate	M$
PV 0%	$ 7,144.8	PV 60%	$ 504.6
PV 10%	$ 3,889.5	PV 70%	$ 256.4
PV 20%	$ 2,533.6	PV 80%	$ 51.5
PV 30%	$ 1,744.8	PV 90%	$ (120.9)
PV 40%	$ 1,208.8	PV 100%	$ (268.1)
PV 50%	$ 812.7		

Type Curve Economics

Alta Mesa – Northwest Area

Well Economics - Summary

Details

Well Name	**335 MBO & 1135 MMCF**
Operator	ALTA MESA
Location	NW AREA
Formation	MISSISSIPPIAN
Project	BAYOU CITY

Input Parameters

Working Interest	100.000%
Net Revenue Interest	83.000%

Return Analysis

IRR	69.0%
ROI	4.03x

Well Rates, Decline Parameters, Reserves

	1st Day Daily	1st Mo Ave	Hyperb b-Fact	De (Aries)	De (Phdw)	Dmin %	Gross EUR	Net EUR BBls,
Oil	458	368	1.15	65.48%	95.0000%	5.0%	335,400	278,382
Gas	814	731	1.25	55.26%	75.0000%	5.0%	1,135,016	612,341
NGL								99,859
MBOE							524,569.14	435,392
MMcfe							3,147	2,612
Water		-	1.2	65.484	95.0%	5.0%	-	

Operating Expenses

Fixed ($/Mo) Esc%	$	5,000.0
Variable:		
Oil ($/Bbl)	$	4.00
Gas ($/Mcf)	$	0.10
Other / Water ($/Bbl)	$	-
Oil Cut (%)		100.0%

Natural Gas Processing

Shrink	35.0%	
Yield	106.0	Bbl/MMcf
Yield	4.5	Gal/Mcf

Pricing

	Initial	Max	% Esc
Oil	$ 45.48	$ 59.03	
Gas	2.43	4.22	
NGL	-	-	

Sev / Ad Valorem Tax

	Initial	Months	Final
Oil	2.00%	36	7.10%
Gas	2.00%	36	7.10%
NGL	2.00%	36	7.10%
Ad Valorem	0.00%	0	0.00%

Economic Results, M$

Net Cumulative Revenue, M$								
Oil	**Gas**	**NGL**	**Total**	**Net Opex**	**Net Sev Ta**	**Net Capita**	**Net Inc**	**Net PV10**
$ 14,068.6	$ 2,106.9	$ 1,924.6	$ 18,100.1	$ 4,225.1	$ 968.1	$ 3,200.0	$ 9,706.9	$ 4,253.4

Finding Co	Gross	Net
$/MBOE	$ 6.10	$ 7.35
$/MMcfe	$ 1.02	$ 1.22

Disc Rate	M$	Disc Rate	M$
PV 0%	$ 9,706.9	PV 60%	$ 58.9
PV 10%	$ 4,253.4	PV 70%	$ (199.4)
PV 20%	$ 2,417.4	PV 80%	$ (407.5)
PV 30%	$ 1,448.5	PV 90%	$ (578.7)
PV 40%	$ 828.1	PV 100%	$ (721.9)
PV 50%	$ 389.0		

Type Curve Economics

Alta Mesa – North Lincoln Area

Well Economics - Summary

Details

Well Name	**185 MBO & 1390 MMCF**
Operator	ALTA MESA
Location	NORTH LINCOLN AREA
Formation	MISSISSIPPIAN
Project	BAYOU CITY

Input Parameters	
Working Interest	100.000%
Net Revenue Interest	83.000%

Return Analysis	
IRR	39.6%
ROI	2.69x

Well Rates, Decline Parameters, Reserves

	1st Day Daily	1st Mo Ave	Hyperb b-Fact	De (Aries)	De (Phdw)	Dmin %	Gross EUR	Net EUR BBls,
Oil	380	270	1.15	65.48%	99.3500%	5.0%	185,034	153,578
Gas	1,502	1,283	1.15	55.26%	87.4000%	5.0%	1,389,144	749,443
NGL								122,217
MBOE							416,557.64	345,743
MMcfe							2,499	2,074
Water		-	1.2	65.484	99.4%	5.0%	-	

Operating Expenses

Fixed ($/Mo) Esc%	$	5,000.0
Variable:		
Oil ($/Bbl)	$	4.00
Gas ($/Mcf)	$	0.10
Other / Water ($/Bbl)	$	-
Oil Cut (%)		100.0%

Natural Gas Processing

Shrink	35.0%	
Yield	106.0	Bbl/MMcf
Yield	4.5	Gal/Mcf

Pricing

	Initial	Max	% Esc
Oil	$ 45.48	$ 59.03	
Gas	2.43	4.22	
NGL	-	-	

Sev / Ad Valorem Tax

	Initial	Months	Final
Oil	2.00%	36	7.10%
Gas	2.00%	36	7.10%
NGL	2.00%	36	7.10%
Ad Valorem	0.00%	0	0.00%

Economic Results, M$

Net Cumulative Revenue, M$ Oil	Gas	NGL	Total	Net Opex	Net Sev Ta	Net Capita	Net Inc	Net PV10
$ 7,667.2	$ 2,493.7	$ 2,320.1	$ 12,481.1	$ 3,214.0	$ 645.0	$ 3,200.0	$ 5,422.0	$ 2,207.7

Finding C	Gross	Net
$/MBOE	$ 7.68	$ 9.26
$/MMcfe	$ 1.28	$ 1.54

Disc Rate	M$	Disc Rate	M$
PV 0%	$ 5,422.0	PV 60%	$ (616.1)
PV 10%	$ 2,207.7	PV 70%	$ (797.5)
PV 20%	$ 1,003.7	PV 80%	$ (943.9)
PV 30%	$ 347.0	PV 90%	$ (1,064.4)
PV 40%	$ (80.1)	PV 100%	$ (1,165.2)
PV 50%	$ (385.3)		

Type Curve Economics

Alta Mesa – South Lincoln Area

Well Economics - Summary

Details

Well Name	**280 MBO & 1165 MMCF**
Operator	ALTA MESA
Location	SOUTH LINCOLN AREA
Formation	MISSISSIPPIAN
Project	BAYOU CITY

Input Parameters		Return Analysis	
Working Interest	100.000%	IRR	107.2%
Net Revenue Interest	83.000%	ROI	3.45x

Well Rates, Decline Parameters, Reserves

	1st Day Daily	1st Mo Ave	Hyperb b-Fact	De (Aries)	De (Phdw)	Dmin %	Gross EUR	Net EUR BBls.
Oil	759	529	1.00	65.48%	99.4500%	5.0%	280,121	232,500
Gas	1,793	1,479	1.00	55.26%	92.2000%	5.0%	1,164,924	628,477
NGL								102,490
MBOE							474,274.72	393,648
MMcfe							2,846	2,362
Water		-	1.0	65.484	99.5%	5.0%	-	

Operating Expenses

Fixed ($/Mo) Esc%	$	5,000.0
Variable:		
Oil ($/Bbl)	$	4.00
Gas ($/Mcf)	$	0.10
Other / Water ($/Bbl)	$	-
Oil Cut (%)		100.0%

Natural Gas Processing

Shrink	35.0%	
Yield	106.0	BBl/MMcf
Yield	4.5	Gal/Mcf

Pricing

	Initial	Max	% Esc
Oil	$ 45.48	$ 59.03	
Gas	2.43	4.22	
NGL	-	-	

Sev / Ad Valorem Tax

	Initial	Months	Final
Oil	2.00%	36	7.10%
Gas	2.00%	36	7.10%
NGL	2.00%	36	7.10%
Ad Valorem	0.00%	0	0.00%

Economic Results, M$

Net Cumulative Revenue, M$								
Oil	Gas	NGL	Total	Net Opex	Net Sev Ta	Net Capita	Net Inc	Net PV10
$ 11,382.2	$ 2,016.7	$ 1,911.9	$ 15,310.8	$ 3,537.0	$ 726.0	$ 3,200.0	$ 7,847.9	$ 4,334.8

Finding C	Gross	Net
$/MBOE	$ 6.75	$ 8.13
$/MMcfe	$ 1.12	$ 1.35

Disc Rate	M$	Disc Rate	M$
PV 0%	$ 7,847.9	PV 60%	$ 726.4
PV 10%	$ 4,334.8	PV 70%	$ 461.5
PV 20%	$ 2,887.9	PV 80%	$ 242.5
PV 30%	$ 2,047.9	PV 90%	$ 58.1
PV 40%	$ 1,477.0	PV 100%	$ (99.5)
PV 50%	$ 1,055.0		

Type Curve Economics

Chaparral – Kingfisher Mississippian

Well Economics - Summary

Details

Well Name **95 MBO & 770 MMCF**
Operator ALTA MESA
Location CHAPARRAL AREA
Formation MISSISSIPPIAN
Project BAYOU CITY

Input Parameters	
Working Interest	100.000%
Net Revenue Interest	83.000%

Return Analysis	
IRR	5.9%
ROI	1.27x

Well Rates, Decline Parameters, Reserves

	1st Day Daily	1st Mo Ave	Hyperb b-Fact	De (Aries)	De (Phdw)	Dmin %	Gross EUR	Net EUR BBls.
Oil	172	134	1.10	65.48%	97.0000%	5.0%	94,744	78,638
Gas	997	822	1.20	55.26%	92.6000%	5.0%	769,037	414,896
NGL								67,660
MBOE							222,916.89	185,021
MMcfe							1,338	1,110
Water		-	1.1	65.484	97.0%	5.0%	-	

Operating Expenses

Fixed ($/Mo) Esc%	$	5,000.0
Variable:		
Oil ($/Bbl)	$	4.00
Gas ($/Mcf)	$	0.10
Other / Water ($/Bbl)	$	-
Oil Cut (%)		100.0%

Natural Gas Processing

Shrink	35.0%	
Yield	106.0	Bbl/MMcf
Yield	4.5	Gal/Mcf

Pricing

	Initial	Max	% Esc
Oil	$ 45.48	$ 59.03	
Gas	2.43	4.22	
NGL	-	-	

Sev / Ad Valorem Tax

	Initial	Months	Final
Oil	2.00%	36	7.10%
Gas	2.00%	36	7.10%
NGL	2.00%	36	7.10%
Ad Valorem	0.00%	0	0.00%

Economic Results, M$

Net Cumulative Revenue, M$ Oil	Gas	NGL	Total	Net Opex	Net Sev Tax	Net Capital	Net Inc	Net PV10
$ 3,900.1	$ 1,350.0	$ 1,274.3	$ 6,524.4	$ 2,120.9	$ 327.1	$ 3,200.0	$ 876.5	$ (362.9)

Finding Cost	Gross	Net
$/MBOE	$ 14.36	$ 17.30
$/MMcfe	$ 2.39	$ 2.88

Disc Rate	M$	Disc Rate	M$
PV 0%	$ 876.5	PV 60%	$ (1,726.1)
PV 10%	$ (362.9)	PV 70%	$ (1,813.5)
PV 20%	$ (924.9)	PV 80%	$ (1,882.4)
PV 30%	$ (1,248.4)	PV 90%	$ (1,937.7)
PV 40%	$ (1,461.3)	PV 100%	$ (1,982.4)
PV 50%	$ (1,612.9)		

BCE
BAYOU CITY ENERGY

1221 McKinney, Suite 2875
Houston, TX 77010
(713) 400-8200

MEMORANDUM

To	File
Date	December 21, 2015
Subject	Alta Mesa Co-Investment Opportunity

When reviewing the Alta Mesa investment opportunity, the General Partner ("GP") determined early on in the process that this investment would be a good candidate for co-investment due to its size. The GP began to reach out to limited partners who were included in the first closing of Bayou City Energy, L.P. (the "Fund") and had expressed an interest in co-investment opportunities. Due to the speed with which it is expected that the investment will close, the GP went to the Fund's largest institutional investors first. Once those investors were notified of the opportunity, the GP began to disseminate the opportunity to prospective LPs that were expected to come into the Fund in the next closing and who had expressed an interest in co-investment.